PB82-239310

Application of Advanced Combustion Modifications to Industrial Process Equipment: Subscale Test Results

KVB, Inc.
Irvine, CA

Prepared for

Industrial Environmental Research Lab.
Research Triangle Park, NC

Apr 82

U.S. Department of Commerce
National Technical Information Service
NTIS

TECHNICAL REPORT DATA

(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA-600/7-82-021	2.	3. RECIPIENT'S ACCESSION NO. PB82-239310
4. TITLE AND SUBTITLE Application of Advanced Combustion Modifications to Industrial Process Equipment: Subscale Test Results		5. REPORT DATE April 1982 6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) S. C. Hunter, W. A. Carter, R. J. Tidona, and H. J. Buening		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS KVB, Inc. P.O. Box 19518 Irvine, California 92714		10. PROGRAM ELEMENT NO. 11. CONTRACT/GRANT NO. 68-02-2645
12. SPONSORING AGENCY NAME AND ADDRESS EPA, Office of Research and Development Industrial Environmental Research Laboratory Research Triangle Park, NC 27711		13. TYPE OF REPORT AND PERIOD COVERED Final; 7/77-10/78 14. SPONSORING AGENCY CODE EPA/600/13

15. SUPPLEMENTARY NOTES IERL-RTP project officer is Robert E. Hall, Mail Drop 65, 919/541-2477.

16. ABSTRACT The report gives results of subscale tests to evaluate combustion modifications for emission control on petroleum process heaters, cement kilns, and steel furnaces. The aim was to assess applicability, NOx emissions reductions, and cost effectiveness of several modifications and to select the most promising for pilot scale tests. Subscale process heater baseline NOx were about 55 ng/J firing natural gas at 2.9 MW heat input. NOx were reduced by 67% with staged combustion and by 63% with flue gas recirculation (FGR). Firing No. 6 oil, baseline NOx of 160 ng/J were reduced by 51% with staged combustion and by 39% with FGR. Staged combustion was selected for pilot scale tests. Subscale cement kiln, baseline NOx were 30-60 ng/J firing natural gas at about 80 kW heat input. Fly ash, kiln dust, water, and sulfur were injected separately to evaluate the NOx reduction potential. Fly ash injection reduced NOx by 28%; the other injectants reduced NOx by 12-20%. Further work at a larger scale is planned prior to selecting modifications for pilot scale tests. For the subscale steel furnace, baseline NOx of 115 ng/J firing natural gas at 0.6 MW heat input were reduced by 88% with FGR and by 47% with water injection. Firing No. 2 oil, baseline NOx of 160 ng/J were reduced by 77% with FGR and by 89% with steam injection.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group	
Pollution	Cements	Pollution Control	13B	11B
Combustion Control	Steel Converters	Stationary Sources	21B	11F
Industrial Processes	Nitrogen Oxides	Combustion Modification	13H	07B
Heating Equipment	Flue Gases	Cement Kilns	13A	
Petroleum Industry		Flue Gas Recirculation	05C	
Kilns				

18. DISTRIBUTION STATEMENT Release to Public	19. SECURITY CLASS *(This Report)* Unclassified	21. NO. OF PAGES 268
	20. SECURITY CLASS *(This page)* Unclassified	22. PRICE

EPA Form 2220-1 (9-73)

United States
Environmental Protection
Agency

EPA-600/7-82-021
April 1982

PB82-239310

EPA

Research and Development

APPLICATION OF ADVANCED COMBUSTION MODIFICATIONS TO INDUSTRIAL PROCESS EQUIPMENT: SUBSCALE TEST RESULTS

Prepared for

Office of Air Quality Planning and Standards

Prepared by

Industrial Environmental Research
Laboratory
Research Triangle Park NC 27711

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SPRINGFIELD, VA 22161

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EPA-600/7-82-021
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U.S. ENVIRONMENTAL PROTECTION AGENCY
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Washington, DC 20460

i-b

ABSTRACT

Results of subscale tests to evaluate combustion modifications for emission control on petroleum process heaters, cement kilns, and steel furnaces are reported. The objective was to assess applicability, NO_x emissions reductions, and cost effectiveness of several modifications and to select the most promising for pilot scale tests. Subscale process heater baseline NO_x emissions were about 55 ng/J firing natural gas at 2.9 MW heat input. NO_x was reduced by 67 percent with staged combustion and by 63 percent with flue gas recirculation. Firing No. 6 oil, baseline NO_x of 160 ng/J was reduced by 51 percent with staged combustion and by 39 percent with flue gas recirculation. Staged combustion was selected for pilot scale tests. Subscale cement kiln baseline NO_x emissions were 30 to 60 ng/J firing natural gas at about 80 kW heat input. Fly ash, kiln dust, water, and sulfur were injected separately to evaluate the NO_x reduction potential. Fly ash injection reduced NO_x emissions by 28 percent, while the other injectants reduced NO_x by 12 to 20 percent. Further work at a larger scale is planned prior to selecting modifications for pilot scale tests. For the subscale steel furnace, baseline NO_x emissions of 115 ng/J firing natural gas at 0.6 MW heat input were reduced by 88 percent with flue gas recirculation and by 47 percent with water injection. Firing No. 2 oil, baseline NO_x emissions of 160 ng/J were reduced by 77 percent with flue gas recirculation and by 89 percent with steam injection.

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ACRONYMS

ACF	Annual Capital Factor
CR	Capital Recovery Factor
FGR	Flue Gas Recirculation
IFC	Initial Fixed Costs
LEA	Lowered Excess Air
NG	Natural Gas
PAR	Primary Air Register
ROR	Rate of Return
SAR	Secondary Air Register
SCA	Staged Combustion Air
TAR	Tertiary Air Register

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ACKNOWLEDGMENTS

The authors wish to acknowledge the assistance of Mr. Robert E. Hall, the EPA Project Officer, whose direction and evaluation were an important contribution to the program.

Acknowledgment is also made of the contributions by the staff and members of the American Petroleum Institute and the Portland Cement Association.

The cooperation of a number of industrial organizations that provided information and allowed tests to be performed on units in their plants is worthy of special acknowledgment.

LIMITATIONS ON APPLICATION OF DATA REPORTED

The pollutant emission data cited in this report are subscale results. These results should not be interpreted as available technology until proven on a full-scale basis.

SECTION 1.0

SUMMARY

1.1 OBJECTIVE AND SCOPE

The objective of this program was to develop advanced combustion modification concepts requiring relatively minor hardware modifications that could be used by operators and/or manufacturers of selected industrial process equipment to control emissions. The development was to be performed for equipment in which the modifications would be most widely applicable and of the most significance in mitigating the impact of stationary source emissions on the environment. The ultimate objective was to demonstrate the feasibility of these modifications to the extent that they could be readily adopted by the fuel burning equipment manufacturers. The path to this goal included concept definitions, economic and technical assessment, subscale performance evaluation tests, cost/benefit analysis, full scale equipment modification or retrofit, full scale performance evaluation tests, and preparation of final reports and instructional guidelines.

Subscale testing is a necessity for some process categories such as petroleum process heaters where equipment operators are naturally reluctant to cooperate in a modification test program until the principle has been demonstrated on a smaller scale. In addition, full scale testing is sometimes required on more than one process design configuration (e.g., forced draft and natural draft) before the equipment manufacturers and process industry will concede that an emission control concept is "demonstrated" or proven current technology.

The program included a survey of equipment in use and tests of representative devices including evaluation of combustion modifications.

This is a final report documenting the subscale activities of the program, including concept definitions, test site survey/selection, subscale test data, and cost analysis.

1.2 PAST WORK

The present program is a follow-on study intended to build upon the results of the program reported in EPA-600/7-79-015a (Ref. 1a). The objective of that earlier effort was to investigate the effectiveness and applicability of combustion modifications involving only operating variable changes as means of improvement in thermal efficiency and for emissions control in industrial and combustion equipment. In that project (EPA Contract No. 68-02-2144), a survey of various kinds of industrial equipment for energy consumption and emissions was conducted. Existing data were collected, and equipment manufacturers, operators, and associations were contacted. Industries were defined for which emissions reduction or efficiency increase through combustion improvement would be of significance on a national basis. These industries were petroleum refining, minerals, paper, and metals. The characteristics of specific combustion equipment of most importance in those industries were defined within the limitations of available data. These characteristics were used as guides in selection of test units that would be most nearly representative of the total population.

The program scope provided for tests on 22 industrial combustion devices representative of kilns, process furnaces, boilers, stationary engines, and gas turbines in industrial use. Emissions measured included NO, NO_x, SO_2, SO_3, CO, CO_2, O_2, gaseous hydrocarbons, and where possible, particulates, particle size distribution, smoke number, and opacity. Combustion modifications evaluated, where possible, included lowered excess air, staged combustion, reduced air preheat, and burner register adjustments. No hardware modifications were attempted, however. All experiments involved only operating changes.

The device types that were tested and a brief summary of NO_x emissions, reductions, and control methods are shown in Table 1-1. In general, the results indicate that combustion modifications could be applied to industrial combustion equipment, but reductions achievable varied significantly for different types of devices. Reductions in NO_x of up to 69% were observed, but on many devices, reductions were less than 10%.

TABLE 1-1. INDUSTRIAL COMBUSTION TEST UNITS SELECTED AND SUMMARY OF RESULTS OBTAINED UNDER EPA CONTRACT 68-02-2144

Device Type	Test Site No.	Rated Heat Input, MW	Fuel	Average Baseline NO_x		Maximum Percent Reduction in NO_x	Combustion Modification[b]
				ng/J[a]	ppm at 3% O_2		
Natural Draft Process Heater	4	25.0	Ref. Gas	59	116	18	4 of 32 BOOS
Natural Draft Process Heater	5/1	15.9	Ref. Gas	50	97	22	Air Register Adjust
Natural Draft Process Heater	5/2	10.1	Ref. Gas	39	76	21	High Load, Low O_2
Natural Draft Process Heater	7/1	15.5	Ref. Gas	52	103	8	2 of 16 BOOS
Natural Draft Process Heater	7/2	11.0	Ref. Gas	49	98	27	Air Register Adjust
Forced Draft Heater, Air Preheat	12/1	27.5	Ref. Gas	163	320	0	Baseline is Lowest NO_x
	12/1		No. 6 Oil	113	222	0	Baseline is Lowest NO_x
Forced Draft Heater, No Air Preheat	12/2	13.6	Ref. Gas	109	214	67	Low O_2
	12/2		No. 6 Oil	97	172	15	Low O_2
Clay Tunnel Kiln	1	9.4	Nat. Gas	46	90	41	Low O_2
Rotary Cement Kiln (Dry Process)	3	70.3	Nat. Gas NG + Coke	903	1460	27	Fuel Switch, Gas to Coke
Rotary Cement Kiln (Wet Process)	9	59.0	Nat. Gas	1319	2250	14	Low O_2, High Air Temperature
Steel Open Hearth Furnace	14	57.0	NG + No. 6 Oil	1094	2070 (Avg)	40	Low O_2
Steel Reheat Furnace	16/1	35.0	Nat. Gas	56	110	43	3 of 27 BOOS
Steel Soaking Pit	16/2	2.9	Nat. Gas	52	101	69	Low O_2
Aluminum Melter	6	10.6	Nat. Gas	49	96	0	Low O_2 (NO_x Increased)
	6		No. 2 Oil	104	185	0	Low O_2 (NO_x Increased)
Wood Bark Boiler	13	34.0	Wood+Coal	188	300	15	Low O_2
Wood Bark Boiler	10/1	69.0	Wood+NG	124	229	23	1 of 4 BOOS
Black Liquor Recovery Boiler	10/2	117.0	Liquor	35	52	30	Secondary Air Adjust
CO Boiler	11	135.0	CO Gas	147	126	12	Air Register Adjust
Natural Gas Engine	2	3.2	Nat. Gas	1020	1990	20	Fuel, Air Adjust
Diesel Engine	15	1.8	No. 2 Oil	904	1611	19	Low Inlet Air Temperature
Gas Turbine Combined Cycle	7/3	230.0	Ref. Gas	59	118	14	1 of 8 BOOS
Gas Turbine Combined Cycle	8	728.0	Ref. Gas	52	103	38	4 of 16 BOOS

[a] 1 lb/10^6 Btu = 430 ng/J

[b] BOOS = Burners Out of Service

1.3 RESULTS

The initial task was to review existing source inventories and update them where possible to more clearly define those processes where controls would be of maximum benefit. The review of source emission data provided a relative ranking of each candidate process. The following steps were followed to accomplish the objective.

1. Identify those industries which are major sources of air pollutant emissions.

2. Identify those industries which are major purchasers of fossil fuel energy.

3. Rank those industries which are both major sources of air pollutant emissions and purchasers of fossil fuel energy.

4. Prepare a list of significant combustion devices involved in the top ranked industries from step 3. These devices will be those which are the major emission sources and energy consumers within their respective industries. Comprehensive listings of stationary combustion devices were employed as a guide in establishing, at least on a generic basis, a checklist of potentially significant devices.

5. Modify this list (step 4) by deleting those combustion devices whose emissions are due to the material being processed and not a result of the combustion process.

6. Again modify the step 4 list by including those devices which by reason of an anticipated high level of commonality offer a widespread usage of emission control techniques obtained on a limited number of tests.

7. Prepare the final listing of devices recommended for field testing.

The equipment recommended for testing included: (1) natural draft process heaters, (2) forced draft process heaters, (3) cement kilns, (4) steel soaking pits and reheat furnaces, (5) glass container furnaces, and (6) wood-bark boilers.

The next task was subscale testing of a small, single-burner natural draft process heater capable of 2.9 MW (10×10^6 Btu/hr) thermal input at a major burner manufacturer's research facility. Two low-NO_x burner designs were tested, and six combustion modifications to two standard burners were evaluated. Both natural gas and oil fuels were fired for evaluation of the combustion modifications. Reduction in NO_x emissions of approximately 60% were measured with flue gas recirculation and with staged combustion while firing natural gas. The NO_x reduction with oil firing was approximately 40% with flue gas recirculation and 50% with staged combustion.

Results of the subscale burner tests are summarized in Appendix A and discussed in detail in Section 4.

Subscale testing of a small one-burner rotary cement kiln capable of 0.0015 Kg/s (12 lb/h) feed rate followed the subscale process heater tests. Several different substances were injected into the flame zone to determine their effects on gaseous emissions, particularly NO_x and SO_2. All tests were carried out firing natural gas with ambient temperature combustion air. Maximum NO_x reduction was 28% with fly ash injection, and less for other materials.

The results of the subscale kiln tests are summarized in Table 5-1 and discussed in Section 5. The report of the cement association which cooperated with KVB for these tests is reproduced in Appendix B.

The third subscale test facility was a small single-burner refractory-lined model of a steel furnace located at the technical center of a major steel furnace burner manufacturer. The maximum heat input capability was 0.59 MW ($2x10^6$ Btu/hr). Steam injection into the flame zone when firing No. 2 oil, and water injection when firing natural gas, were evaluated with regard to their effects on NO_x emission and efficiency. Flue gas recirculation, firing both No. 2 oil and natural gas (not simultaneously), was also evaluated. Steam injection resulted in a maximum NO emission reduction of 89%, and water injection led to a maximum 47% NO reduction. Flue gas recirculation produced a maximum 77% NO reduction firing No. 2 oil and an 88% reduction firing natural gas.

The results of the subscale steel furnace experiments are covered in Section 6 and Appendices C and D.

1.4 CONCLUSIONS AND RECOMMENDATIONS

From the data obtained and the analyses made during this program, the following conclusions and recommendations may be made.

1.4.1 Subscale Process Heater

1. For a subscale natural draft process heater, baseline NOx levels for two standard burners ranged from 54.6 to 67.0 ng/J firing natural gas. One standard burner was found to emit 150 ng/J firing No. 6 oil and 63 ng/J firing No. 2 oil.

2. Two low-NOx burner designs had baseline NOx emissions ranging from 47.1 to 53.0 ng/J firing natural gas. Thus, the mean NOx emission level from these burners was about 18% lower than the mean value for the two standard burners. Firing No. 6 oil, one low-NOx burner design produced 149 ng/J, a reduction of 7% below the standard burner. The reduction of NOx due to the low-NOx burner when firing No. 2 oil was only 2% below the standard burner baseline.

3. Combustion modification techniques were effective in reducing NOx emissions on a subscale process heater firing either natural gas or No. 6 oil. Staged combustion air accomplished by lances through the heater floor and coupled with lowered excess air was the most effective technique, followed by flue gas recirculation at either normal or reduced excess air. When properly adjusted and under reduced excess air conditions, a low-NOx (tertiary air design) burner was also shown to be effective in lowering NOx emissions firing both natural gas and No. 6 oil fuel. Lowered excess air alone without other modifications was not very effective in reducing the NOx concentration when firing No. 6 oil.

4. Modifications which worked well firing gas fuel but which were not tried firing oil because of time or test equipment limitations included staged combustion air using a central cylinder above the primary air zone, steam

injection, and altered fuel injection geometry. Each of these modifications reduced NOx emissions by more than 30% below baseline and some may be applicable to oil firing as well as gas firing.

5. Staged combustion air by means of floor lances reduced the NOx at a normal operating excess air level by 46% below baseline (54.6 ng/J) firing natural gas fuel. At lowered O_2 levels the reduction was as much as 67% (natural gas fuel). At normal O_2 conditions the NOx reduction firing No. 6 oil was 35% below baseline (160 ng/J) and at reduced O_2, the reduction reached 51%. This staged air technique was also the most cost-effective technique based on the data available. Costs are predicted to be roughly $700/Mg of NOx reduction for small heaters (2.9 MW and below) firing gas dropping to only $39/Mg of NOx reduction for large heaters (147 MW and above) firing oil.

6. Cost calculations did not include annual fuel costs or savings due to the combustion modifications because of the unrealistic efficiency changes that were observed on the small-scale heater. In the case of staged combustion air, however, no large effect on efficiency is foreseen except in cases where excess air can be reduced. Then, the efficiency can be expected to increase with the application of staged air.

1.4.2 Pilot Cement Kiln

1. In all tests, the NOx levels observed were well below those previously reported for full-scale kilns indicating that the subscale unit was not truly representative of a production kiln. It is thought that the use of ambient temperature combustion air as well as a high gas-to-solids ratio in the small kiln were the primary factors contributing to low-NOx emissions.

2. Although the absolute NOx levels may not have accurately reflected those present in a full-scale kiln, the trends in emission levels which resulted from the injection of sulfur, water, kiln dust, and fly ash should still provide a basis for determining the relative effectiveness of each injected material in reducing NOx. With that in mind, it was discovered that fly ash injection was the most effective of the above in reducing NOx emissions. At normal operating O_2, NOx emissions were reduced by 28% of the baseline value when fly ash was injected into the flame zone. Clinker quality was actually slightly improved during those tests. Injection of the other materials reduced the NOx levels by 12 to 20% with essentially no effect on product quality.

3. Lowered excess air (<1.5% O_2) was not a practical NOx reduction technique for the pilot kiln. Accompanying CO levels were high and clinker quality was degraded. In general, it was found, the recent industry already maintains the lowest practical oxygen levels in most kilns (1.5-2.0% O_2).

1.4.3 Subscale Steel Furnace

1. For the two fuels tested, natural gas and No. 2 oil, flue gas recirculation proved to be the most effective combustion modification applied to the subscale unit. Steam injection was effective firing No. 2 oil but was not tried firing natural gas because of constraints in the test apparatus. Water injection was less effective firing natural gas than steam injection was firing oil.

2. Twenty percent flue gas recirculation applied at normal O_2 levels reduced NOx emissions firing gas fuel by 88% and firing No. 2 oil by 77%. Cost analyses showed that FGR is the most attractive combustion modification for larger furnaces (73.3 MW and up) provided the waste heat of the recirculated flue gas is recovered. However, FGR is not as cost effective as steam injection firing No. 2 oil for heaters smaller than about 13.5 MW nor is it as cost effective as water injection firing natural gas for heaters under 8.5 MW in size.

1.4.4 Recommendations

Based on the test results on the subscale process heater, KVB recommends testing the staged air lances on a pilot scale process heater. The test variables should include injection height and pattern, the burner stoichiometric ratio, the excess air level, and system performance as a function of load. Natural gas, refinery gas, and residual fuel oil should be tested as these are the fuels most commonly used at refineries.

Because of the very low NOx concentrations measured in the pilot cement kiln, KVB recommends further subscale studies in its own laboratory. A nonproducing, nonrotating model should be constructed and tests made in which the level of air preheat is varied. Other operating variables which should be investigated include inside wall temperature, primary and secondary air velocities, and primary air vitiation (variation of O_2 in the primary air stream). Tests should be done for coal firing and for natural gas firing.

Post-combustion-zone mechanisms of NOx formation as well as near-burner mechanisms should be considered in order to insure that NOx destroyed at the burner end of the kiln will not be recreated at the opposite end of the kiln. A full-scale kiln should be tested with the most promising combustion modification techniques.

Both steam injection and flue gas recirculation should be applied to a full-scale steel furnace based on the results of the subscale tests reported here. Appropriate methods to recover the waste heat of the recirculated flue gas stream or the steam such as heat exchangers or condensation heat recovery devices could be employed to minimize efficiency losses due to these modifications. The possibility of doing this should be investigated. Application of steam injection firing gas fuel should be investigated in order to verify that the technique is effective for that fuel as well as for No. 2 oil.

SECTION 2.0

CONCEPT DEFINITION

The objectives of this project element were (1) to review the source emission data on several industrial combustion processes and to rank the processes according to NO_x emission and fossil fuel consumption, (2) to define combustion modification concepts having the most promise for reducing emissions and increasing efficiency for those processes ranking highest in NO_x emission and fuel consumption, and (3) to evaluate process constraints for each candidate combustion device so as to determine the effect of combustion modifications on product flow and integrity as well as the applicability of various modification concepts over a broad range of unit types within each industrial process category.

2.1 PROCESS EMPHASIS

Activity in the concept definition task concentrated on the review of processes to be emphasized in the test program:

1. Petroleum process heaters
2. Cement kilns
3. Steel reheat furnaces
4. Steel soaking pits
5. Wood-bark boilers
6. Glass furnaces

For each category the following information was sought:

1. Total number of devices in the U.S.
2. Total production rate per year
3. Total fuel heat input per year
4. Average device size
5. Average or typical emission factor
6. Total NO_x emissions per year

Table 2-1 presents this information. Whenever possible, values in Table 2-1 have been taken from KVB's own experience. The emission factors for all of the categories other than glass container furnaces were determined from previous KVB field tests. Every effort has been made to avoid the use of raw NEDS (National Emission Data System) data in making up Table 2-1. All sources of information have been referenced.

The emissions estimates can serve only as a rough guide to ordering priorities for the test program. The accuracy and precision of estimated national NO_x emissions from the industrial process categories is primarily dependent on the ability to accurately determine total fuel consumption (or product output) and emission factors. Most of the differences between the estimates in Table 2-1 and other estimates are due to large differences in emission factors, up to a factor of 10 in some cases. Most contractors doing national emissions surveys use EPA emission factors obtained from AP-42 or data obtained from the NEDS system. KVB has used recent but limited data for emission factors. There is considerable uncertainty regarding the accuracy (true mean) of these emission factors, and information on the precision (standard deviation) is sketchy.

The ranking by NO_x emission of the industrial processes being considered for testing was as follows:

1. Cement kilns - 704 Gg/y (776,000 tons/y)
2. Wood-bark boilers - 141 Gg/y (157,000 tons/y)
3. Refinery process heaters - 121.5 Gg/y (134,000 tons/y)
4. Glass container furnaces - 38.9 Gg/y (42,900 tons/y)
5. Steel soaking pits and reheat furnaces - 286 Gg/y (31,500 tons/y)

The ranking of the industrial processes by total annual heat input was as follows:

1. Refinery process heaters - $1.58\text{x}10^{18}$ J ($1.5\text{x}10^{15}$ Btu)
2. Wood-bark boilers - $915\text{x}10^{15}$ J ($873\text{x}10^{12}$ Btu)
3. Steel soaking pits and reheat furnaces - $538\text{x}10^{15}$ J ($510\text{x}10^{12}$ Btu)
4. Cement kilns - $513\text{x}10^{15}$ J ($486\text{x}10^{12}$ Btu)
5. Glass container furnaces - $105\text{x}10^{15}$ J ($99.6\text{x}10^{12}$ Btu)

Table 2-2 compares the NO_x emissions and the annual heat inputs for the candidate processes.

TABLE 2-1. INDUSTRIAL PROCESS CHARACTERISTICS AND NO_x EMISSIONS

Source Category	Refinery Process Heaters		Glass Container Furnaces	Cement Kilns	Steel Furnaces		Wood/Bark Boilers
Subheading (Reference)	Natural Draft (1)	Forced Draft (1)	All (2)	All (KVB Analysis)	Soaking Pits (KVB Analysis)	Reheat Furnaces (KVB Analysis)	All (j) (KVB Analysis)
Number of units in U.S.	∿5400	∿600	334	412 (in 1975)	1435 (d)	1264 (d)	∿ 1700
Average design capacity per unit, SI (customary)	---	---	1.57 kg/s (150 t/d)	6.60 kg/s (629 t/d)	5.0 kg/s (20 t/h)	25.2 kg/s (100 t/h) (e)	18.8 MW heat absorbed (64,000 lb steam/h)
Average design heat input rate per unit MW(Btu/h)	8.06 (27.5x10^6)	11.1 (38x10^6)	13.1 (44.6x10^6)	39.8 (136x10^6)	7.3 (f) (25x10^6)	88.0 (300x10^6)	23.5 MW (80x10^6)
Total actual annual production kg (tons)	---	---	12.656x10^9 (13.953x10^6)	84.8x10^9 (93.5x10^6)	----	---	328x10^9 (k) (364x10^6 tons steam)
Average heat input per unit of throughput (J/kg (Btu/t))	---	---	8.29x10^6 (a) (7.14x10^6)	6.04x10^6 (b) (5.2x10^6)	1.45x10^6 (1.25x10^6) (g)	3.48x10^6 (3.0x10^6) (g)	2.8x10^6 (l) (2.4x10^6)
Total annual heat input J (Btu)	1.37x10^{18} (1.3x10^{15})	211x10^{15} (200x10^{12})	105x10^{15} (99.6x10^{12})	513x10^{15} (486x10^{12})	185x10^{15} (h) (175x10^{12})	353x10^{15} (h) (335x10^{12})	915x10^{15} (873x10^{12})
Average emission factor, ng/J (lb/10^6 Btu)	68.8 (0.16)	133.3 (0.31)	370 (0.861)	1372 (c) (3.19)	56 (i) (0.13)	52 (i) (0.12)	156 (m) (0.36)
Total NO_x emission Gg/y (t/y)	93.4 (103,000)	28.1 (31,000)	38.89 (42,900)	704 (776,000)	10.32 (11,375)	18.23 (20,100)	141 (157,000)

NOTES:
(a) based on unpublished data from California Air Resources Board study of SOx emission by KVB.
(b) from Reference 3
(c) average of emission factors determined from two field tests conducted by KVB as reported in Reference 4.
(d) from Reference 5
(e) from Reference 6 (average for slab reheat furnaces)
(f) from Reference 7
(g) from References 3, 6 and 7
(h) from Reference 3 (total annual heat input for both soaking pits and reheat furnaces combined) and Reference 8 (fraction of total heat input to soaking pits, fraction to reheat furnaces)
(i) from KVB tests as reported in Reference 4
(j) based on 1977 NEDS point source listing (Ref. 9) with KVB emission factor
(k) assumes operation at 80% rated load for 11 months out of the year
(l) assumes heat requirement of 1200 Btu/lb of steam
(m) from Reference 4; average for wood + coal and wood + NG boilers.

TABLE 2-2. NO_x EMISSIONS AND TOTAL ANNUAL HEAT INPUT FOR INDUSTRIAL PROCESS EQUIPMENT BEING CONSIDERED FOR TESTING

	NO_x Emissions Gg/y (tons/y)	Total Annual Heat Input J (Btu)
Natural draft process heaters	93.4 (103,000)	1.37×10^{18} (1.3×10^{15})
Forced draft process heaters	28.1 (31,000)	211×10^{15} (200×10^{12})
Cement kilns	704 (776,000)	513×10^{15} (486×10^{12})
Steel soaking pits and reheat furnaces	28.6 (31,500)	538×10^{15} (510×10^{12})
Glass container furnaces	38.9 (42,900)	105×10^{15} (99.6×10^{12})
Wood-bark boilers	141 (157,000)	915×10^{15} (873×10^{12})

On the basis of the data presented here KVB decided to concentrate its efforts on selecting petroleum process heaters, cement kilns, wood-bark boilers, and steel furnaces as potential test sites.

Subscale test work has now been completed on a vertically-fired, rectangular process heater, a rotary dry process cement kiln, and a subscale steel furnace. The process heater subscale tests were conducted in conjunction with a major process heater burner manufacturer. The subscale steel furnace was tested in conjunction with a major steel furnace burner manufacturer. The research kiln tests were conducted at the laboratory of a major cement industry association.

Full-scale test sites at which KVB has completed testing include two wood-bark boilers, a lime kiln, a refinery process heater, and two cement kilns. The full-scale test results will be reported elsewhere.

2.2 DEFINING COMBUSTION MODIFICATIONS

A list of candidate combustion modifications was prepared for each of the three subscale test sites. These modifications involved minor hardware changes as well as operating changes in the case of the subscale process heater. Only a limited number of modifications including the injection of various materials into the flame zone were tried with the subscale cement kiln because of the small size of the kiln.

2.2.1 Process Heater Combustion Modification Concepts

There are two general approaches that merited consideration in performing combustion modifications on process heaters. In natural draft devices, the air flow, mixing, and flame shape are intimately interrelated in that air flow adjustments to alter burner stoichiometry have a negative impact on the other parameters. Therefore, some consideration was given to varying burner stoichiometry by controlling the fuel flow and injection pressure or velocity. Another approach to limiting NO_x formation in the flame zone is to control the local mixing and flame zone intensity by minor burner design modifications to achieve more desirable temperature and stoichiometry conditions.

In chronological order, the modifications tested in the subscale process heater were the following:

1. Lowered excess air
2. Low-NO_x burners (two designs)
3. Steam injection
4. Staged combustion (two methods)
5. Flue gas recirculation
6. Modified fuel injection

Each of these concepts is defined in Section 4 of this report. A summary of test results for each modification is also given in that section.

2.2.2 Cement Kiln Combustion Modification Concepts

Rotary kilns present a difficult task for combustion modification because they have only a single burner, and the product quality is very dependent upon temperature. Because of the unique combustion system design and process operating constraints, combustion modification requires careful consideration of process temperature requirements. Modified combustion system operating techniques which were evaluated included lowered excess air, and injection into the flame zone of steam, sulfur, and fly ash. These modifications are explained along with test results in Section 5 of this report.

2.2.3 Steel Furnace Combustion Modification Concepts

The small size and easy accessibility of the research steel furnace tested on this program made it a logical choice for the generally more cumbersome modifications of H_2O injection and flue gas recirculation. The burner manufacturer also had existing steam and water-injection capability as well as a suitable fan for the flue gas recirculation tests. There, the modifications tested in the subscale steel furnace were the following:

1. Lowered excess air
2. Varied heat input rates
3. Steam injection (firing No. 2 oil fuel)
4. Water injection (firing natural gas)
5. Flue gas recirculation (firing No. 2 oil and NG)

The discussion of these modifications is continued in Section 6.

It is believed that these modifications were preferable to those involving burner stoichiometry changes because of product quality considerations. Although perhaps not quite as much as in a cement kiln, the required operating conditions in a steel furnace place restrictions on the oxidizing/reducing characteristics of the flame; hence, there is little flexibility for making stoichiometry changes, particularly in a single-burner application.

2.3 EXAMINING PROCESS CONSTRAINTS

2.3.1 Natural Draft Process Heaters

The following constraints pose limitations on any modifications tried.

1. Because of the very small pressure drop across a natural draft burner, special care must be taken to avoid an unstable flame when making modifications which alter the structure of the burning zone.
2. Process heaters generally run at or near full capacity so that any modification which would result in a lowering of process rate is undesirable (particularly in retrofit applications).
3. Flame impingement on walls or tubes should be avoided.

2.3.2 Cement Kilns

The process constraints are considerably more restrictive for cement kilns than they are for process heaters. Some of these constraints are identified as follows:

1. The crystal structures of the cement clinker components tricalcium silicate, $3CaO \cdot SiO_2$ ($\equiv C_3S$) and dicalcium silicate, $2CaO \cdot SiO_2$ ($\equiv C_2S$) are a function of temperature profile. The size and shape of each of the two types of crystals depend upon the residence times at certain temperatures of the kiln feed mix. C_2S crystal size increases with the amount of time spent over 1723 K. C_3S

crystal size increases with the amount of time spent between 1473 K and 1723 K. The kiln temperature profile depends on the flame length. A long flame implies a long residence time between 1473 K and 1723 K and a short time over 1723 K, whereas a short flame implies a short residence time between 1473 K and 1723 K but a long time over 1723 K (as shown in Figure 2-1). A long flame, often preferable to a short flame from the standpoint of NO_x emissions, is usually detrimental to product quality in a cement kiln. With a long flame, the C_3S crystals grow to be too large and the C_2S crystals are too small. In addition, the C_2S crystals lose their circular shape and become jagged as a result of slow cooling in a long flame. These jagged crystals are not hydraulically active and, therefore, in a long flame the 28-day compression strength of the cement can be reduced to as little as half of the desired value. If the cement strength is too low, the user must mix more cement with the aggregate in order for the concrete strength to meet specifications.

2. When firing oil or natural gas 1-1.5% excess O_2 is generally maintained. As a rule, when firing coal 1% of primary air is used for each 1% of volatile matter in the coal.

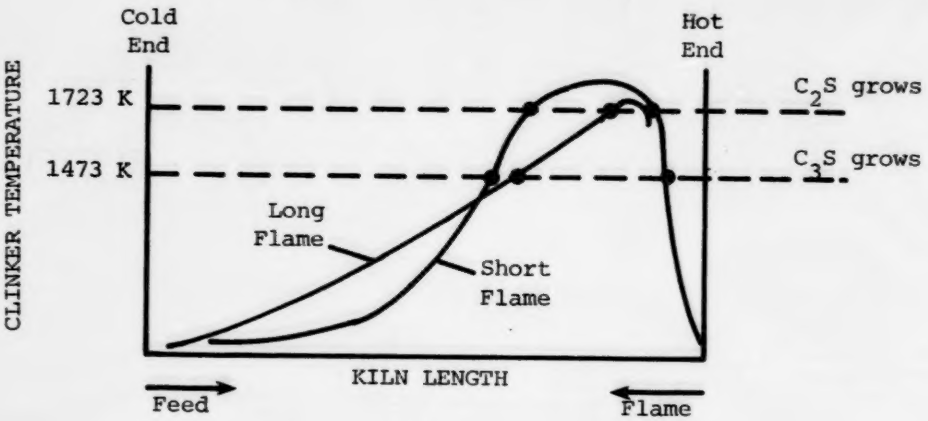

Figure 2-1. Effect of kiln temperature profile on crystal structure of the clinker.

3. The temperatures required in the flame zone are determined by the burnability of the feed mix as characterized by four modulae: the lime saturation factor, silica modulus, iron modulus, and percent liquid phase modulus. With the first three modulae, the higher the number, the harder the mix is to burn; hence higher temperatures are associated with higher modulae values. The reverse is true of the percent liquid phase modulus, i.e., a lower value of this modulus implies a harder-burning mix. The burnability modulae are defined as follows:

1. Lime Saturation Factor (LSF) =

$$\frac{\%\ CaO}{2.8(\%\ SiO_2) + 1.1(\%\ Al_2O_3) + 0.72(\%\ Fe_2O_3)}$$

$$= 0.87 - 0.95 \text{ typically}$$

2. Silica Modulus (SM) = $\frac{\%\ SiO_2}{\%\ Al_2O_3 + \%\ Fe_2O_3}$

3. Iron Modulus (IM) = $\frac{\%\ Al_2O_3}{\%\ Fe_2O_3}$

4. Percent Liquid Phase Modulus = $1.13(C_3A) + 1.35\ (C_4AF) + MgO$ + alkalies

= 23 - 26% typically

Note: $C_3A \equiv$ tricalcium aluminate, $3CaO \cdot Al_2O_3$

$C_4AF \equiv$ tetracalcium alumina ferrite, $4CaO \cdot Al_2O_3 \cdot Fe_2$

(Both are liquids above 473 K)

An overabundance of the liquid phase will erode the kiln coating. The burning modulae are measured on the feed mix, but if coal is burned the fly ash should also be included in determining the modulae.

2.3.3 Steel Furnaces

Steel furnace combustion modifications are subject to the following important process limitations:

1. The temperature in a reheat furnace or soaking pit must be maintained at a constant level in each zone of the furnace. This level is often about 1533K (2300°F). Proper temperature distribution assures uniform heating of the steel with no localized overheating of an ingot, slab, billet, or bloom.

2. The heating rate in the furnace may not exceed the ability of the steel to safely absorb heat. Variations in firing rates may cause problems in furnace heat distribution.

3. The range of fuel-air ratios is limited by scaling problems at the steel surface. Too much or too little oxygen can result in undesirable scale losses.

4. Furnace draft is sometimes used to control heat distribution in steel furnaces. There may be times when this draft setting will limit the excess air variations which could be made on a furnace.

SECTION 3.0

EMISSIONS TEST METHODS AND INSTRUMENTATION

The process heater emission measurements were made with instrumentation carried in a 2.4m x 9.8m mobile laboratory which was described in detail in the EPA Report Application of Combustion Modification to Industrial Combustion Equipment, Contract No. 68-02-2144.

All emission measurement instrumentation was transferred and reinstalled in a new 2.4 x 12.8m laboratory trailer. This trailer was used for the tests at the subscale cement kiln. A plan view of the trailer is shown in Figure 3-1. The gaseous species measurements are made with analyzers located in the trailer, while the smoke spot and sulfur oxides measurements are made at the sample port, and the titration is done in or near the trailer.

The emission measurement instrumentation used is the following:

TABLE 3-1. EMISSION MEASUREMENT INSTRUMENTATION

Species	Manufacturer	Measurement Method	Model No.
Hydrocarbon	Beckman Instruments	Flame Ionization	402
Carbon Monoxide	Beckman Instruments	IR Spectrometer	865
Oxygen	Teledyne	Polarographic	326A
Carbon Dioxide	Beckman Instruments	IR Spectrometer	864
Nitrogen Oxides	Thermo Electron Co.	Chemiluminescent	10A
Sulfur Dioxide	DuPont Instruments	UV Spectrometer	400
Sulfur Oxides	KVB Equipment Co.	Controlled Condensation	--
Smoke Spot	Bacharach	ASTM D2156-65	21-7006

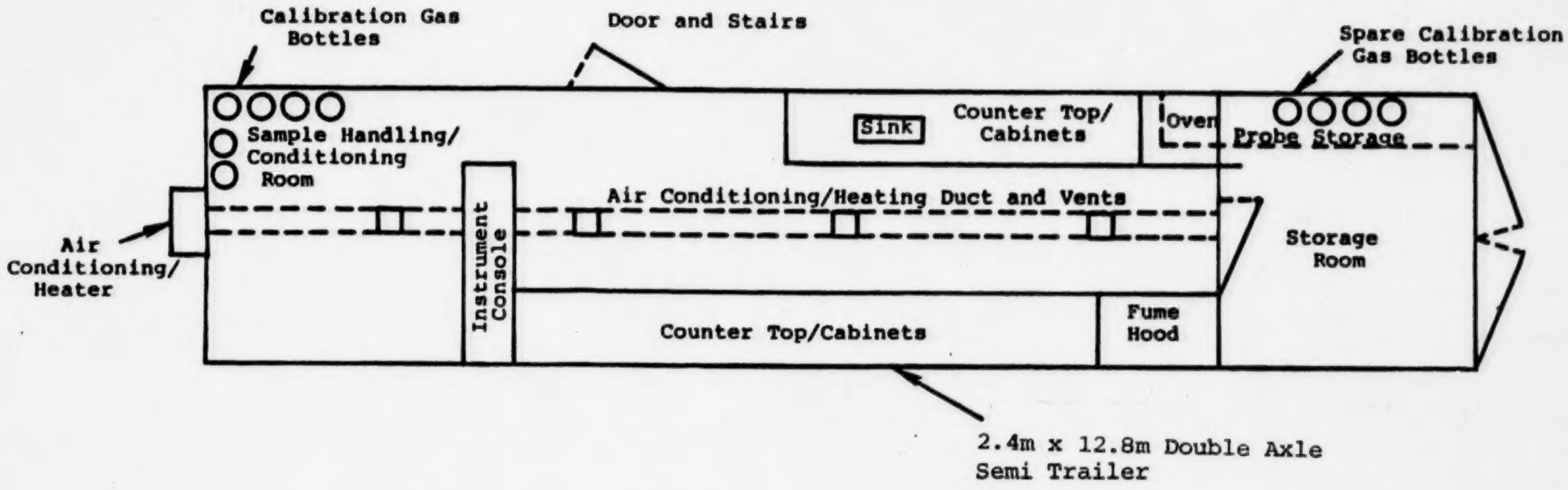
Calibration Gas Bottles
Door and Stairs
Spare Calibration Gas Bottles
Sample Handling/ Conditioning Room
Sink
Counter Top/ Cabinets
Oven
Probe Storage
Air Conditioning/ Heater
Instrument Console
Air Conditioning/Heating Duct and Vents
Storage Room
Fume Hood
Counter Top/Cabinets
2.4m x 12.8m Double Axle Semi Trailer

Figure 3-1. Instrumentation trailer floor plan.

3.1 GAS SAMPLING AND CONDITIONING SYSTEM

A flow schematic of the flue gas sampling and analyzing system is shown in Figure 3-2. The sampling system uses three positive-displacement diaphragm pumps to continuously draw flue gas from the stack into the laboratory. The sample pumps pull from six unheated sample lines. Selector valves allow composites of up to six points to be sampled at one time. The probes are connected to the sample pumps with 0.95 cm (3/8") or 0.64 cm (1/4") nylon line. The positive displacement diaphragm sample pumps provide unheated sample gas to the refrigerated condenser (to reduce the dew point to 275 K), a rotameter with flow control valve, and to the O_2, NO, CO, and CO_2 instrumentation. Flow to the individual analyzers is measured and controlled with rotameters and flow control valves. Excess sample is vented to the atmosphere.

To obtain a representative sample for the analysis of NO_2, SO_2 and hydrocarbons, the sample must be kept above its dew point, since heavy hydrocarbons may be condensible, and SO_2 and NO_2 are quite soluble in water. For this reason, a separate electrically-heated sample line is used to bring the sample into the laboratory for analysis. The sample line is 0.64 cm (1/4-inch) Teflon line, electrically traced and thermally insulated to maintain a sample temperature of up to 478 K. Metal bellows pumps provide sample to the hydrocarbon, SO_2 and NO_x analyzers.

3.2 INSTRUMENTAL CONTINUOUS MEASUREMENTS

The laboratory trailer is equipped with analytical instruments to continuously measure concentrations of NO, NO_2, CO, CO_2, O_2, SO_2, and hydrocarbons. All of the continuous monitoring instruments and sample handling system are mounted in the self-contained mobile laboratory. The entire system requires only connection to on-site water, power, and sampling lines to become fully operational. The instruments themselves are shock mounted on a metal console panel. The sample flow control measurement, and selection, together with instrument calibration are all performed from the console face.

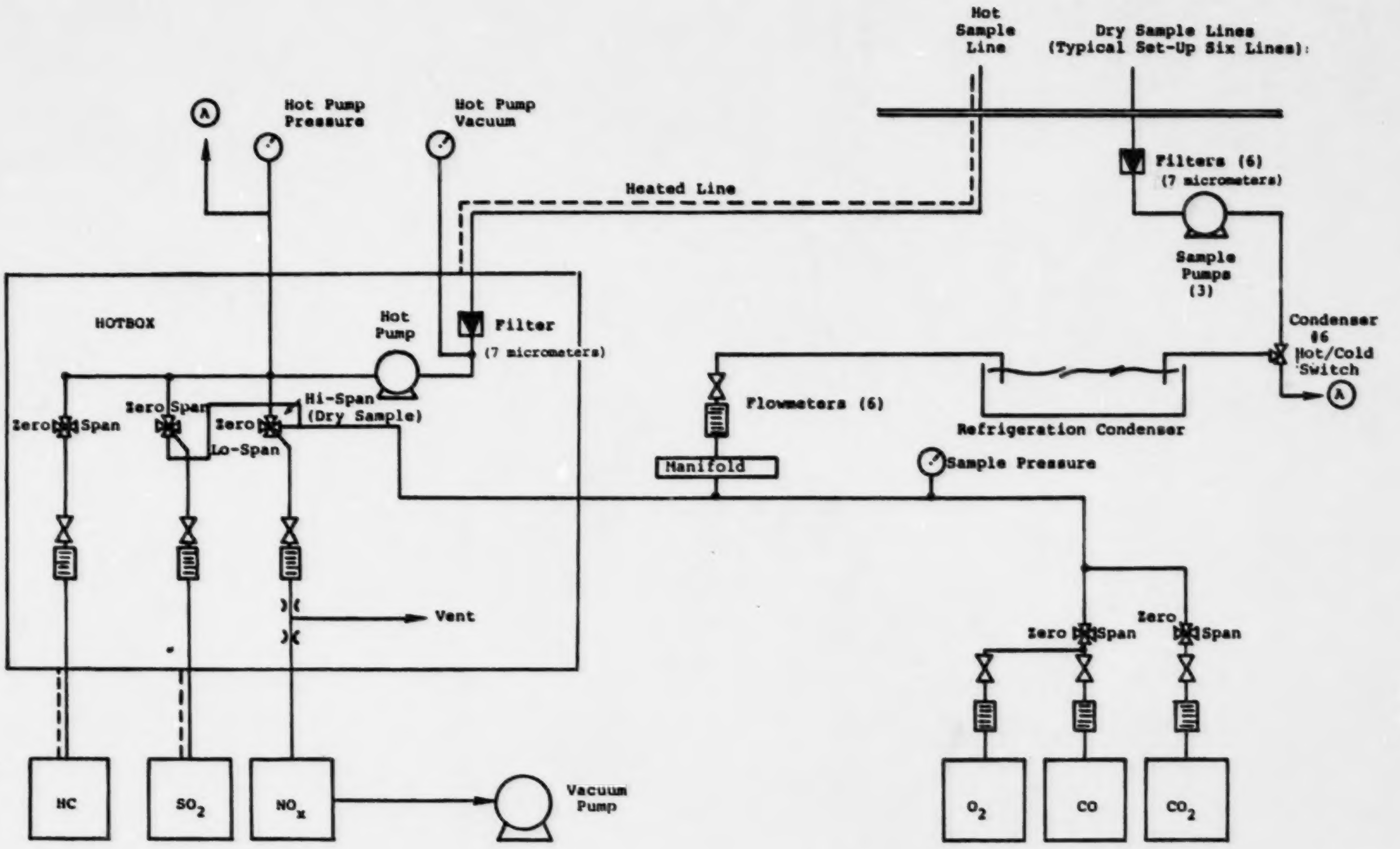
Hot Sample Line
Dry Sample Lines (Typical Set-Up Six Lines):
Ⓐ
Hot Pump Pressure
Hot Pump Vacuum
Heated Line
Filters (6) (7 micrometers)
Sample Pumps (3)
HOTBOX
Hot Pump
Filter (7 micrometers)
Condenser #6 Hot/Cold Switch
Ⓐ
Flowmeters (6)
Refrigeration Condenser
Zero
Span
Zero
Span
Zero
Hi-Span (Dry Sample)
Lo-Span
Manifold
Sample Pressure
Vent
Zero
Span
Zero
Span
HC
SO_2
NO_x
Vacuum Pump
O_2
CO
CO_2

Figure 3-2. Flue gas sampling and analyzing system.

Three-pen recorders provide a continuous permanent record of the data taken. The sample gas is delivered to the analyzers at the proper condition and flow rate through the sampling and conditioning system described in the previous section. The sections below describe the analytical instrumentation.

3.2.1 Nitric Oxide (NO) and Total Nitrogen Oxides (NO_x)

Both the total nitrogen oxides (NO_x) and nitric oxide (NO) concentrations are measured from a sample gas obtained using a heated sample line at 394 K (250 °F). In addition, the nitric oxide concentrations are measured sequentially from samples obtained using the unheated sample line that is connected to the same analyzer in the laboratory trailer. In the latter case, water is first removed from the sample gas by a refrigeration unit. The analytical instrument that is used for all of these measurements is the Thermo Electron Model 10A chemiluminescent gas analyzer.

For NO analyses, the sample gas is passed directly into the reaction chamber where a surplus of ozone is maintained. The reaction between the NO and the ozone produces light energy proportional to the NO concentration which is detected with a photomultiplier and converted to an electrical signal. Air for the ozonator is drawn from ambient through an air dryer and a 10-micron filter element. Flow control for the instrument is accomplished by means of a small metal bellows pump mounted in a heated box.

The chemiluminescent reaction with ozone is specific for NO. To detect NO_2, a thermal converter has been designed to dissociate the NO_2 to NO by the bi-molecular reaction: $2\ NO_2 \overset{\Delta}{\rightarrow} 2\ NO + O_2$. A model 700 thermal converter is used in conjunction with the chemiluminescent gas analyzer as shown in Figure 3-3. The converter is a coil of resistance-heated stainless steel tubing whose purpose is to drive the NO_2/NO ratio to its chemical equilibrium value at the converter temperature and pressure. The unit is designed to operate at a temperature of 923 K (1200 °F) and pressure of 1.3 kPa (10 torr). For these conditions and typical stack gas O_2 concentrations, the equilibrium NO_2 concentration is 0.2% of the total NO_x concentration. Therefore, when a gas sample containing any NO_2 is passed through the converter, essentially all the NO_2 would be converted to NO. The resulting total NO is then measured using the chemiluminescent analyzer and the difference between the actual NO and the "total NO" would be the sample NO_2 concentration. The "total NO" is interpreted as NO_x.

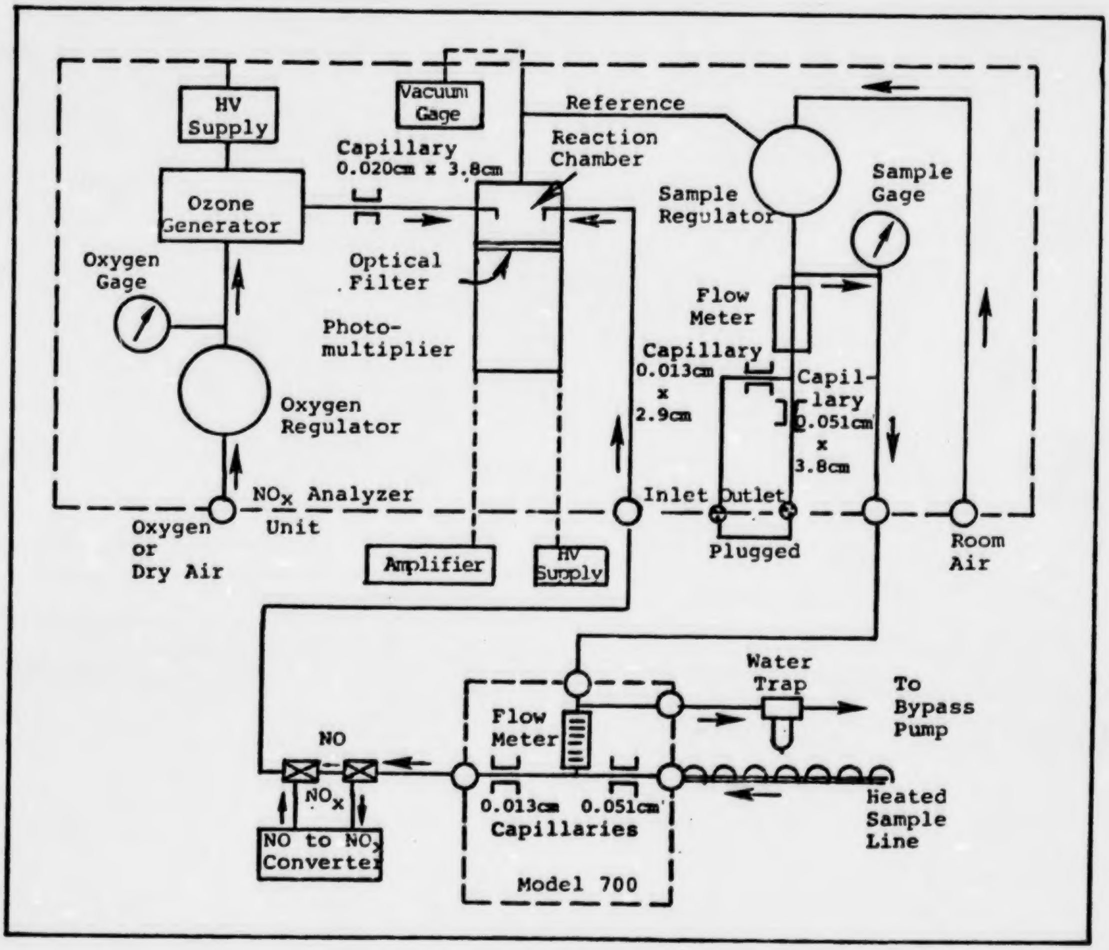
HV Supply
Vacuum Gage
Reference
Capillary 0.020cm x 3.8cm
Reaction Chamber
Ozone Generator
Sample Regulator
Sample Gage
Oxygen Gage
Optical Filter
Flow Meter
Photo-multiplier
Capillary 0.013cm x 2.9cm
Capil-lary 0.051cm x 3.8cm
Oxygen Regulator
NO$_x$ Analyzer Unit
Inlet
Outlet
Oxygen or Dry Air
Amplifier
HV Supply
Plugged
Room Air
Water Trap
To Bypass Pump
Flow Meter
NO
NO$_x$
0.013cm
0.051cm
Capillaries
Heated Sample Line
NO to NO$_x$ Converter
Model 700

Figure 3-3. Schematic of NO_x/NO chemiluminescent analysis system.

NO_2 may react upon contact with H_2O (liquid phase) to form HNO_3 (nitric acid). Under field test conditions, the exhaust gas may contain significant H_2O (depending upon the process and the ambient meteorological conditions), and it is necessary to convert the NO_2 to NO before the H_2O is allowed to condense in the sampling system. By using the heated sample line and the Thermo Electron Model 700 heated NO_x module, NO_2 concentrations will effectively be measured. In reference to Figure 3-3, the sample is maintained above the H_2O dew point up to and through the 127 μm (0.005 in.) capillary in the heated module. Downstream of this capillary, the flow network is maintained at 1.3 kPa (10 torr), where the partial pressure of the H_2O in the sample is sufficiently low to prevent any condensation at ambient temperature.

When using the heated system, NO, NO_2, and NO_x are measured on a wet basis. When not using the heated system, a condenser is placed upstream of the analyzer and NO is measured on a dry basis.

Specifications

Accuracy: 1% of full scale
Span stability: ± 1% of full scale in 24 hours
Zero stability: ± 1 ppm in 24 hours
Power requirements: 115 ± 10V, 60 Hz, 1000 watts
Response: 90% of full scale in 1 sec (NO_x mode); 0.7 sec (NO mode)
Output: 4-20 ma
Sensitivity: 0.5 ppm
Linearity: ± 1% of full scale
Vacuum detector operation
Range: 2.5, 10, 25, 100, 250, 1000, 2500, 10,000 ppm full scale

3.2.2 Carbon Monoxide and Carbon Dioxide (CO and CO_2)

Carbon monoxide and carbon dioxide concentrations are measured using Beckman Model 864 and 865 short-path-length nondispersive infrared analyzers (see Figure 3-4). These instruments measure the differential in infrared

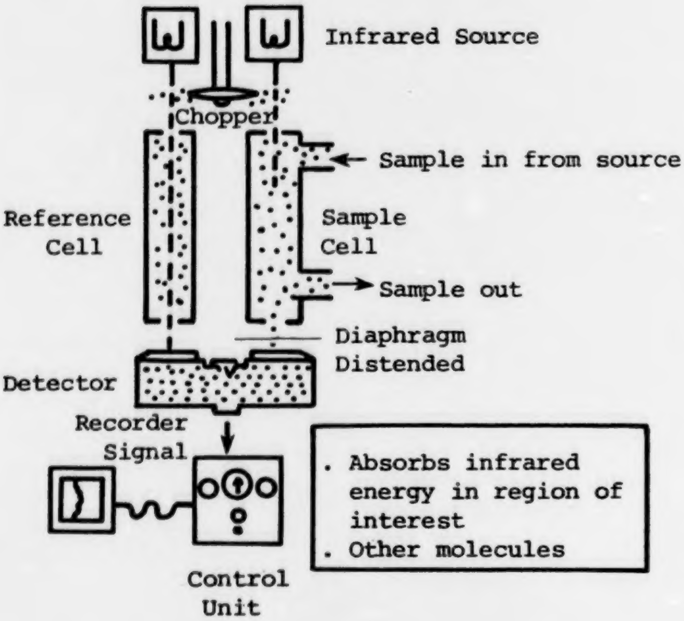
Infrared Source
Chopper
Sample in from source
Reference Cell
Sample Cell
Sample out
Diaphragm Distended
Detector
Recorder Signal
Control Unit
. Absorbs infrared energy in region of interest
. Other molecules

Figure 3-4. Schematic of NDIR analyzer.

energy absorbed from energy beams passed through a reference cell (containing a gas selected to have minimal absorption of infrared energy in the wavelength absorbed by the gas component of interest) and a sample cell through which the sample gas flows continuously. The differential absorption appears as a reading on a scale of 0% to 100% and is then related to the concentration of the species of interest by calibration curves supplied with the instrument. A linearizer is supplied with each analyzer to provide a linear output over the range of interest. The operating ranges for the CO analyzer are 0-100 and 0-2000 ppm, while the ranges for the CO_2 analyzer are 0-5% and 0-20%.

Specifications

Span stability: ± 1% of full scale in 24 hours
Zero stability: ± 1 ppm in 24 hours
Ambient temperature range: 273 to 322 K (32 °F to 120 °F)
Line voltage: 115 ± 15V rms
Response: 90% of full scale in 0.5 or 2.5 sec
Linearity: Linearizer board installed for one range
Precision: ± 1% of full scale
Output: 4-20 ma

3.2.3 Oxygen (O_2)

A Teledyne Model 326A oxygen analyzer is used to automatically and continuously measure the oxygen content of the flue gas sample. The analyzer utilizes a micro-fuel cell which is specific for oxygen, has an absolute zero, and produces a linear output from zero through 25% oxygen. The micro-fuel cell is a sealed electrochemical transducer with no electrolyte to change or electrodes to clean. Oxygen in the flue gas diffuses through a Teflon membrane and is reduced on the surface of the cathode. A corresponding oxidation occurs at the anode internally and an electric current is produced that is proportional to the concentration of oxygen. This current is measured and conditioned by the instrument's electronic circuitry to give an output in percent O_2 by volume for operating ranges of 0% to 5%, 0% to 10%, and 0% to 25%.

Specifications

Precision: ± 1% of full scale

Response: 90% in less than 40 sec

Sensitivity: 1% of low range

Linearity: ± 1% of full scale

Ambient temperature range: 273 K to 325 K (32 to 125 °F)

Fuel cell life expectancy: 40,000%+-hrs

Power requirement: 115 VAC, 50-60 Hz, 100 watts

Output: 4-20 ma

3.2.4 Total Hydrocarbons (HC)

Hydrocarbon emissions are measured using a Backman Model 402 high-temperature hydrocarbon analyzer. The analyzer utilizes the flame ionization method of detection which is a proven technique for a wide range of concentrations (0.1 to 120,000 ppm). A flow schematic of the analyzer is presented in Figure 3-5. The sensor is a burner where a regulated flow of sample gas passes through a flame sustained by regulated flows of air and a premixed hydrogen/nitrogen fuel gas. Within the flame the hydrocarbon components of the sample stream undergo a complex ionization that produces electrons and positive ions. Polarized electrodes collect these ions, causing current to flow through electronic measuring circuitry. Current flow is proportional to the rate at which carbon atoms enter the burner.

The analysis occurs in a temperature-controlled oven. The sample is extracted from the stack with a stainless steel probe which has been thermally treated and purged to eliminate any hydrocarbons existing in the probe itself. An insulated heat-traced teflon line is used to transfer the sample to the analyzer. The entire heated network is maintained at a temperature to prevent condensation of heavier hydrocarbons.

The flame ionization detector is calibrated with methane, and the total hydrocarbon concentration is reported as the methane equivalent. FID's do not respond equally to all hydrocarbons but generally provide a measure of the carbon-hydrogen bonds present in the molecule. The FID does not detect pure carbon or hydrogen.

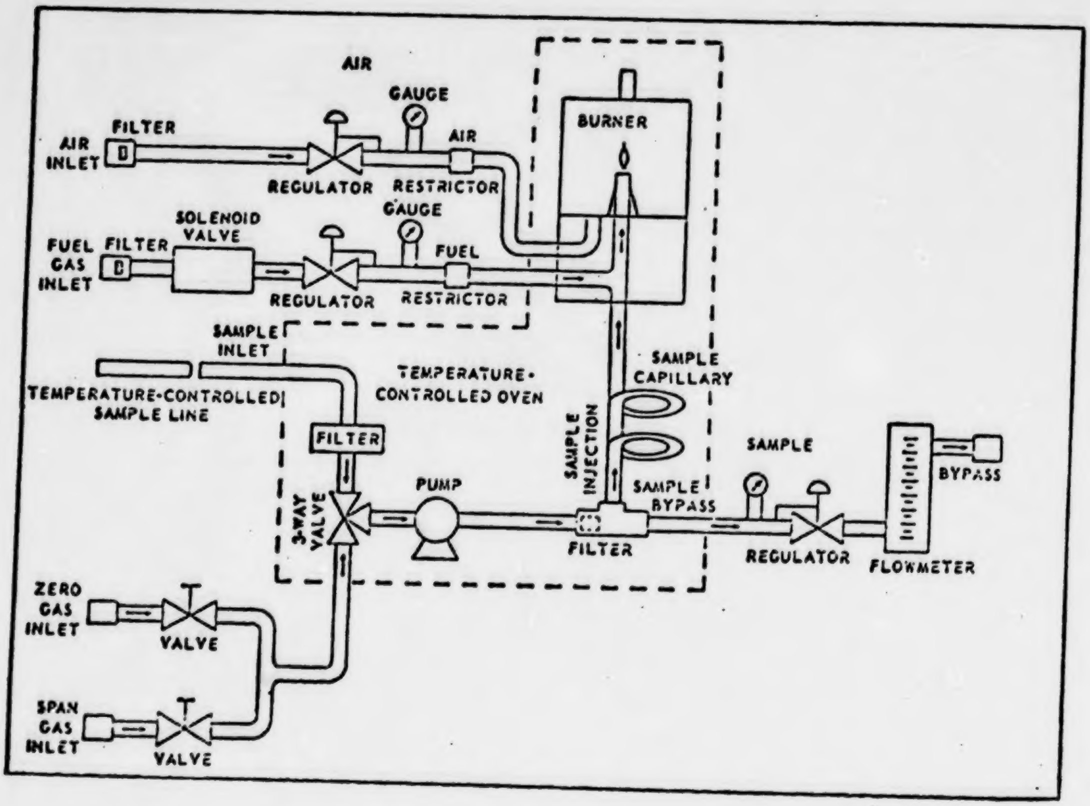
AIR
AIR INLET
FILTER
REGULATOR
GAUGE
AIR
RESTRICTOR
BURNER
FUEL GAS INLET
FILTER
SOLENOID VALVE
REGULATOR
GAUGE
FUEL
RESTRICTOR
SAMPLE INLET
TEMPERATURE-CONTROLLED SAMPLE LINE
TEMPERATURE-CONTROLLED OVEN
SAMPLE CAPILLARY
SAMPLE INJECTION
FILTER
3-WAY VALVE
PUMP
FILTER
SAMPLE BYPASS
SAMPLE
REGULATOR
FLOWMETER
BYPASS
ZERO GAS INLET
VALVE
SPAN GAS INLET
VALVE

Figure 3-5. Flow schematic of hydrocarbon analyzer (FID).

Specifications

Full-scale sensitivity: adjustable from 5 ppm CH_4 to 10% CH_4

Ranges: Range multiplier switch has 8 positions: X1, X5, X10, X50, X100, X500, X1000, and X5000. In addition, span control provides continuously variable adjustment within a dynamic range of 10:1

Response time: 90% full scale in 0.5 sec

Precision: ± 1% of full scale

Electronic stability: ± 1% of full scale per 24 hours with ambient temperature change of less than 10 °F

Reproducibility: ± 1% of full scale for successive identical samples

Analysis temperature: ambient

Ambient temperature: 273 K to 317 K (32 °F to 110 °F)

Output: 4-20 ma

Air requirements: 250 to 400 cc/min of clean, hydrocarbon-free air, supplied at 2.07×10^5 to 1.38×10^6 n/m^2 (30 to 200 psig)

Fuel gas requirements: 75 to 80 cc/min of fuel consisting of 100% hydrogen supplied at 2.07×10^5 to 1.38×10^6 n/m^2 (30 to 200 psig)

Electric power requirements: 120 V, 60 Hz

Automatic flame indication and fuel shut-off valve

3.2.5 Sulfur Dioxide (SO_2)

A Dupont Model 400 photometric analyzer is used for measuring SO_2. This analyzer measures the difference in absorption of two distinct wavelengths (ultraviolet) by the sample. The radiation from a selected light source passes through the sample and then into the photometer unit where the radiation is split by a semi-transparent mirror into two beams. One beam is directed to a phototube through a filter which removes all wavelengths except the "measuring" wavelength, which is strongly absorbed by the constituent in the sample. A second beam falls on a reference phototube, after passing through an optical filter which transmits only the "reference" wavelength. The latter is absorbed only weakly, or not at all, by the constituent in the sample cell. The phototubes translate these intensities to proportional electric currents in the amplifier. In the amplifier, full correction is made for the logarithmic relationships between the ratio of the intensities and concentration or thickness (in accordance with Beer's Law). The output is therefore linearly proportional, at all times, to the concentration and thickness of the sample. The instrument has a lower detection limit of 2 ppm and full scale ranges of 0-200 and 0-2000 ppm.

Specifications

Noise: Less than 1/4%

Drift: Less than 1% full scale in 24 hours

Accuracy: (± 1% of analyzer reading)+(± 1/4% of full scale range)

Sample cell: 304 stainless steel, quartz windows

Flow rate: 6 CFH

Light source: Either mercury vapor, tungsten, or "Osram" discharge type lamps

Power rating: 500 watts maximum, 115 V, 60 Hz

Reproducibility: 1/4% of scale

Electronic response: 90% in 1 sec

Sample temperature: 378 K (220 °F)

Output: 4-20 ma d.c.

3.3 SULFUR OXIDES (SO_x)

Goksoyr-Ross Method--Wet Chemical Method

The Goksoyr-Ross Controlled Condensate (G/R) method is used for the wet chemical SO_2/SO_3 determination. It is a desirable method because of its simplicity and clean separation of particulate matter, SO_2 and H_2SO_4 (SO_3). This procedure is based on the separation of H_2SO_4 (SO_3) from SO_2 by cooling the gas stream below the dew point of H_2SO_4 but above the H_2O dew point. Figure 3-6 illustrates schematically the G/R test system.

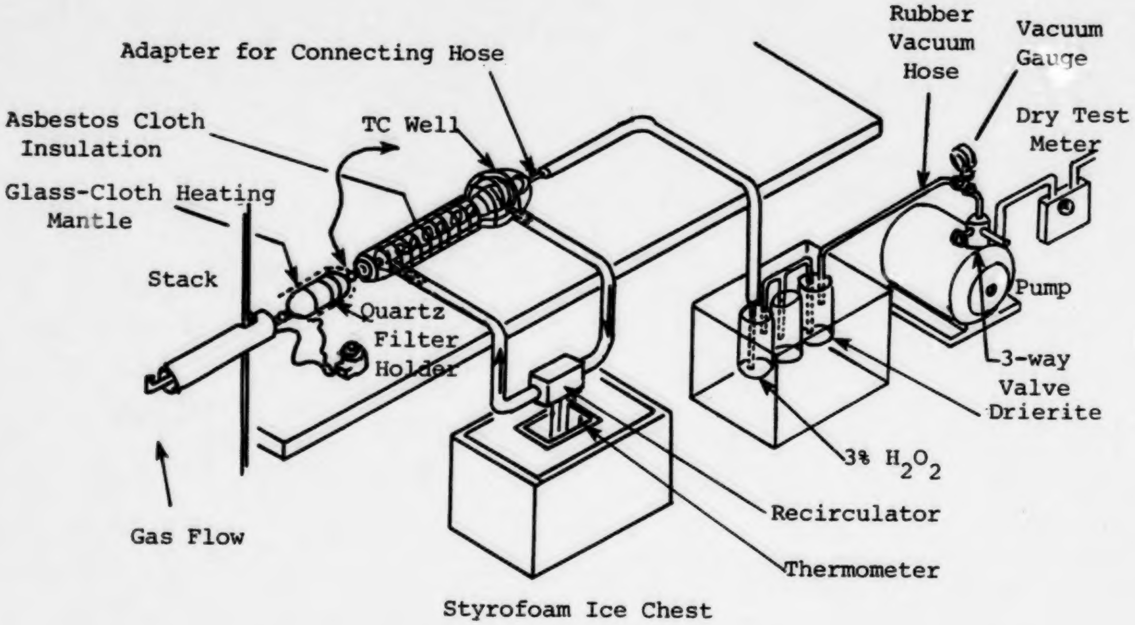
Adapter for Connecting Hose
Rubber Vacuum Hose
Vacuum Gauge
Asbestos Cloth Insulation
TC Well
Dry Test Meter
Glass-Cloth Heating Mantle
Stack
Quartz Filter Holder
Pump
3-way Valve
Drierite
$3\% \ H_2O_2$
Recirculator
Thermometer
Gas Flow
Styrofoam Ice Chest

Figure 3-6. Schematic of Goksoyr-Ross Controlled Condensation System (CCS).

Particulate matter is first removed from exhaust gas stream by means of a quartz glass filter placed in the heated glass filter holder. Tissue-quartz filters are recommended because of their proven inertness to H_2SO_4. The filter system is heated by a heating tape so that the gas out temperature of 260 °C (500 °F) is maintained. This temperature is imperative to ensure that none of the H_2SO_4 will condense in the filter holder or on the filter.

The condensation coil where the H_2SO_4 is collected is cooled by water which is maintained at 60 °C (140 °F) by a heater/recirculator. This temperature is adequate to reduce the exhaust gas to below the dew point of H_2SO_4.

Three impingers are shown in Figure 3-6. The first impinger is filled with 3% H_2O_2 to absorb SO_2; the second impinger is to remove carry-over moisture; and the third contains a thermometer to measure the exhaust gas temperature to the dry gas meter and pump. The sampling rate is 2.3 lpm (0.08 CFM).

Analysis Procedure

For both SO_2 and H_2SO_4 determination, the analytical procedure is identical. The H_2SO_4 sample is washed from the back part of the filter holder and the coil using distilled water. The sample from the first impinger which is assumed to be absorbed and reacted SO_2 in the form of H_2SO_4 is recovered with distilled water washing. The amount of H_2SO_4 in the condensate from the coil and from the H_2O_2 impinger is measured by H+ titration. Bromphenol Blue is used with NaOH as the titrant.

3.4 SMOKE SPOT

On combustion equipment where smoke numbers normally are taken, such as oil-fired boilers, KVB, Inc. determines the smoke number using test procedures according to ASTM Designation: D 2156-65. The smoke number is determined at each combustion modification setting of the unit. Examples are baseline, minimum excess air, low load, etc., and whenever a particulate concentration is measured.

Smoke spots are obtained by pulling a fixed volume of flue gas through a fixed area of a standard filter paper. The color (or shade) of the spots that are produced is visually matched with a standard scale. The result is a "Smoke Number" which is used to characterize the density of smoke in the flue gas.

The sampling device is a hand pump similar to the one shown in Figure 3-7. It is a commercially available item that can pass 36,900 ± 1650 cu cm of gas at 289K and 1 atmosphere pressure through an enclosed filter paper for each 6.5 sq cm effective surface area of the filter paper.

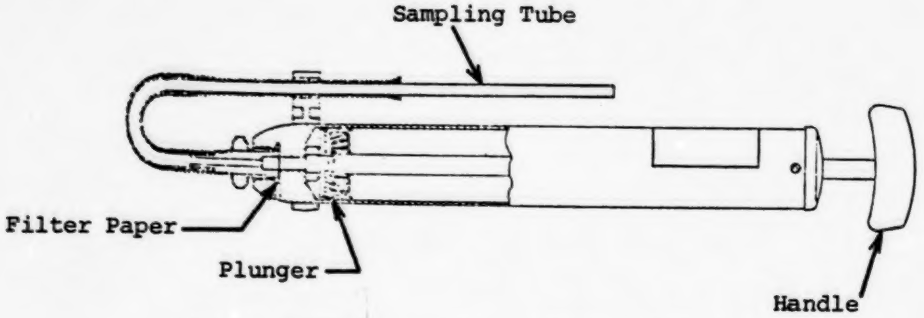

Figure 3-7. Field-service-type smoke tester.

The smoke spot sampler is provided with a motor-driven actuator to ensure a constant sampling rate independent of variations in stroke rate that can occur when the sampler is operated manually.

The smoke scale required consists of a series of ten spots numbered consecutively from 0 to 9, and ranging in equal photometric steps from white through neutral shades of gray to black. The spots are imprinted or otherwise processed on white paper or plastic stock having an absolute surface reflectance of between 82.5 and 87.5%, determined photometrically. The smoke scale spot number is defined as the reduction (due to smoke) in the amount of light reflected by a soiled spot on the filter divided by 10.

Thus the first spot, which is the color of the unimprinted scale, is No. 0. In this case there is no reduction in reflected incident light directed on the spot. The last spot, however, is very dark, reflecting only 10% of the incident light directed thereon. The reduction in reflected incident light is 90%, and this spot is identified as No. 9. Intermediate spot numbers are similarly established. Limits of permissible reflectance variation of any smoke scale spot will not exceed ± 3% relative reflectance.

The test filter paper is made from white filter paper stock having absolute surface reflectance of 82.5 to 87.5%, as determined by photometric measurement. When making this reflectance measurement, the filter paper is backed by a white surface having absolute surface reflectance of not less than 75%.

When clean air at standard conditions is drawn through clean filter paper at a flow rate of 47.6 cu cm per sec per sq cm effective surface area of the filter paper, the pressure drop across the filter paper falls between the limits of 1.7 and 8.5 kPa (1.3 and 6.4 cm of mercury).

The sampling procedure is exactly that specified in D 2156. A clean, dry, sampling pump is used. It is warmed to room temperature to prevent condensation on the filter paper. When taking smoke measurements in the flue pipe, the intake end of the sampling probe is placed at the center line of the flue. When drawing the sample, the pressure in the flue gas stream and the sampler is allowed to equalize after each stroke.

The smoke density is reported on the Mobile Lab Data Sheet as the Smoke Spot Number on the standard scale most closely corresponding to test spot. Differences between two standard Smoke Spot Numbers are interpolated to the nearest half number. Smoke Spot Numbers higher than 9 are reported as "Greater than No. 9."

This procedure is deemed to be reproducible to within ± 1/2 of a Smoke Spot Number under normal conditions where no oily stain is deposited on the disk.

KVB's field experience with industrial boilers has been that the human factor involved in the interpretation of the smoke spot by an experienced observer does not cause a significant lack of precision.

SECTION 4.0

SUBSCALE PETROLEUM PROCESS HEATER RESEARCH

This section summarizes the emission and efficiency data collected for the subscale petroleum process heater tests. Also discussed is the cost-effectiveness study conducted for the natural draft heaters. The results presented herein summarize the equipment characteristics, special instrumentation requirements, gaseous emissions data, combustion modifications, efficiency, cost effectiveness, and conclusions and recommendations.

4.1 SUBSCALE TEST - PETROLEUM PROCESS HEATER

The testing covered in this section was conducted either in a research furnace of a major manufacturer of natural draft burners or in a cold flow model in the KVB laboratory.

4.1.1 Process Heater (Location 1) - Equipment Characteristics

The process heater subscale testing was conducted in the research furnace of a major manufacturer of natural draft burners. The furnace was a refractory lined, uncooled rectangular box type furnace 2.4 m (8') wide by 1.8 m (6') deep by 9.8 m (32') high.

The natural draft burner was installed in the furnace floor firing vertically upward. Furnace draft was controlled manually with a damper in the stack. View ports for observing flame shape were provided.

The furnace had the capability of firing either oil or natural gas, and both flows were measured with flow meters. Thermocouples were installed in the side of the furnace to indicate the vertical thermal gradient and to show when the furnace was up to operating temperature. Figure 4-1 shows the placement of thermocouples in the furnace.

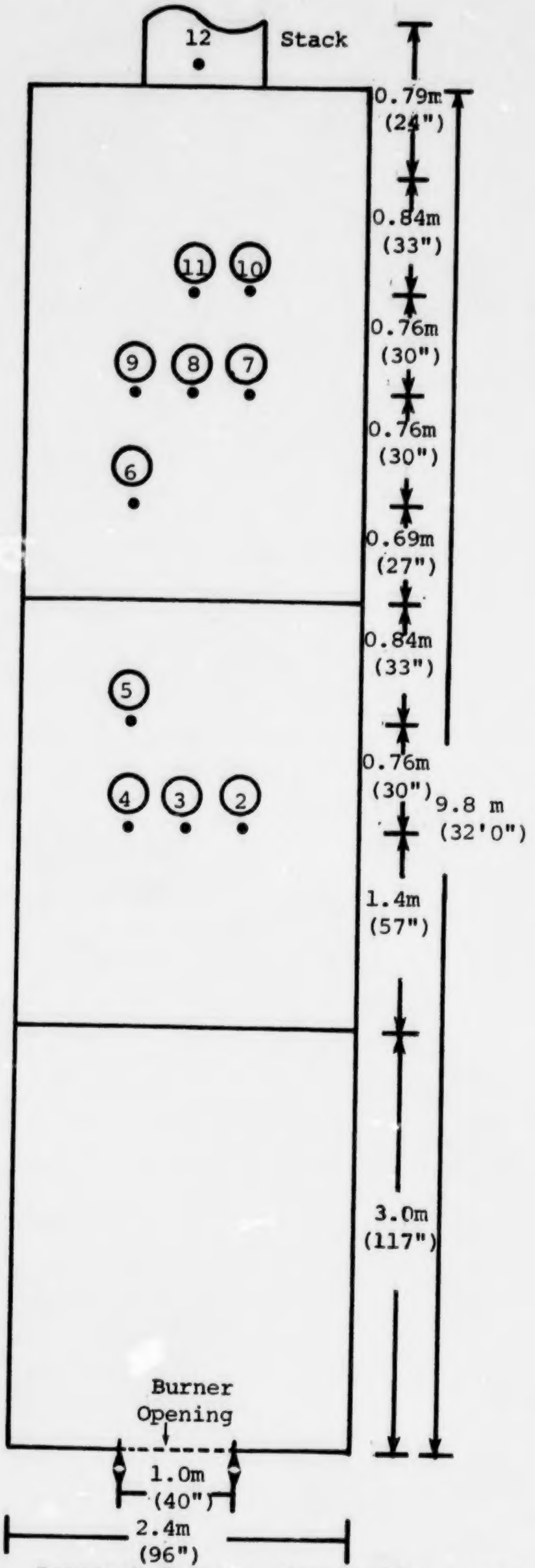
12
Stack
0.79m
(24")
0.84m
(33")
0.76m
(30")
0.76m
(30")
0.69m
(27")
0.84m
(33")
0.76m
(30")
9.8 m
(32'0")
1.4m
(57")
3.0m
(117")
11
10
9
8
7
6
5
4
3
2
Burner
Opening
1.0m
(40")
2.4m
(96")

Figure 4-1. Research furnace thermocouple location.

4.2 BURNER COLD FLOW TESTS

A cold flow burner model simulating the natural draft burner was fabricated at the KVB laboratory. The cold flow model was built to the same dimensions as the burner tested in the research furnace. The purpose of the cold flow tests was to develop an analytical mixing model to provide insight into fuel injection modifications which could lead to lowered NO_x emissions.

The model had the same air flow and velocity as the actual burner. The natural gas was simulated by gasous CO_2. Fuel injection momentum was the same as in the actual burner. Measurements of fuel concentration were made in two axes across the firebox at three axial planes. Contour maps of constant concentration were prepared to compare the mixing characteristics of the different gun tips. After the mixing model was prepared, modifications to the gas tips were made and tested.

Tests were conducted with three standard gas tips supplied by the burner manufacturer. The gas fuel was simulated by CO_2 and the concentration measured with an NDIR CO_2 analyzer. Actual burner fuel air ratio and the cold flow simulation are related by the following expression:

$$(F/A)_{Burner} = (F/A)_{Sim.} \left[(\rho_f/\rho_{air})_{Burner} \, (\rho_{air}/\rho_f)_{Sim} \right]^{1/2}$$

A schematic of the flow system is shown in Figure 4-2. Sample ports were located at three axial positions approximately 5, 36, and 66 cm (2, 14, and 26 inches) above the gas injection plane. At each axial position sample ports were on the burner center line and 5 cm (2 inches) apart to the edge of the burner, then 10 cm (4 inches) apart from the burner to the walls. Figure 4-3 presents the pattern for the sample ports. Sample ports not being used were covered to prevent influx of air.

The results of the measurements for nozzle configuration No. 2 are shown in Figures 4-4 and 4-5.

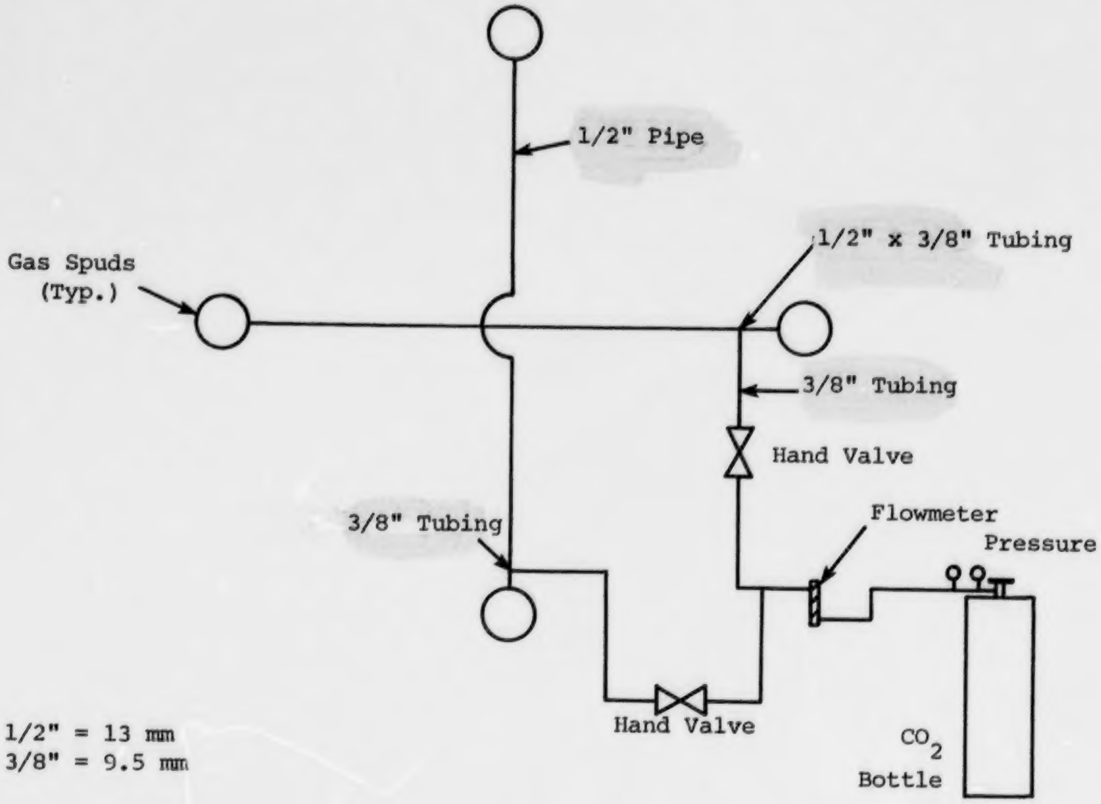
1/2" Pipe
1/2" x 3/8" Tubing
Gas Spuds
(Typ.)
3/8" Tubing
Hand Valve
3/8" Tubing
Flowmeter
Pressure
Hand Valve
CO_2
Bottle
1/2" = 13 mm
3/8" = 9.5 mm

Figure 4-2. Schematic of cold flow model.

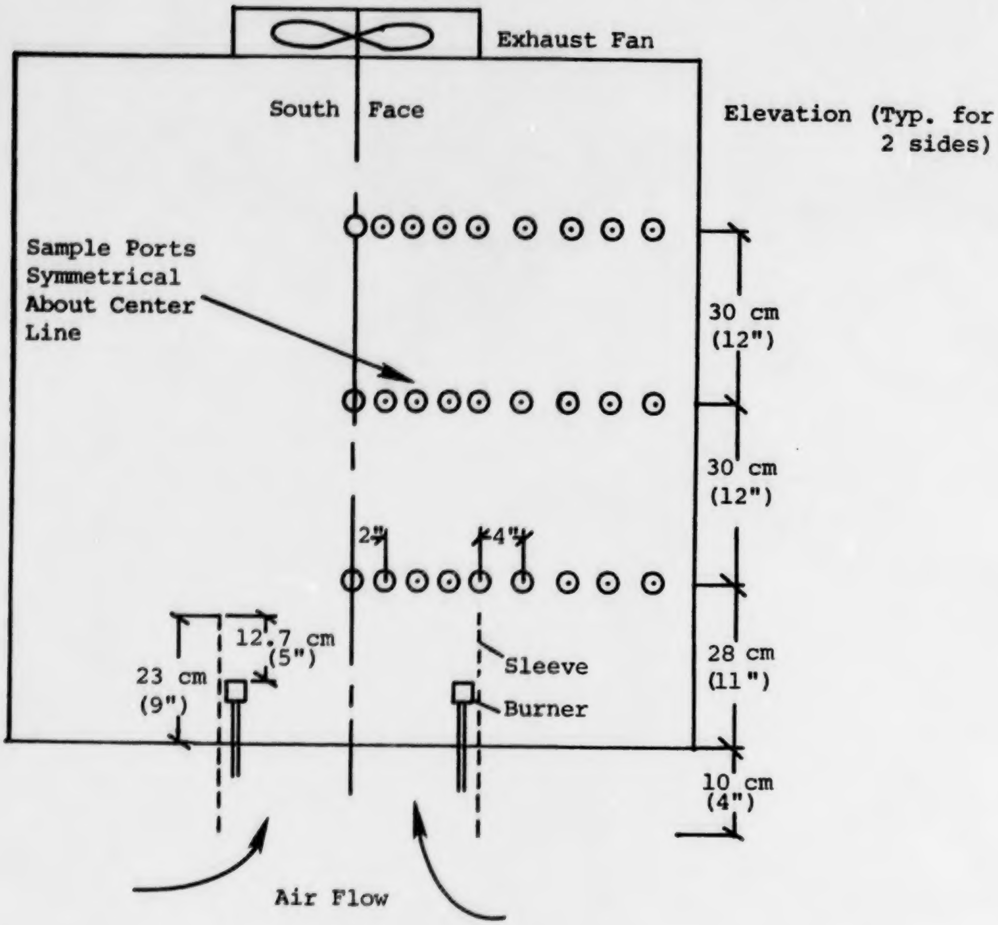
Exhaust Fan
South Face
Elevation (Typ. for 2 sides)
Sample Ports Symmetrical About Center Line
30 cm (12")
30 cm (12")
2"
4"
28 cm (11")
12.7 cm (5")
23 cm (9")
Sleeve
Burner
10 cm (4")
Air Flow

Figure 4-3. Schematic of burner cold flow model showing sampling locations.

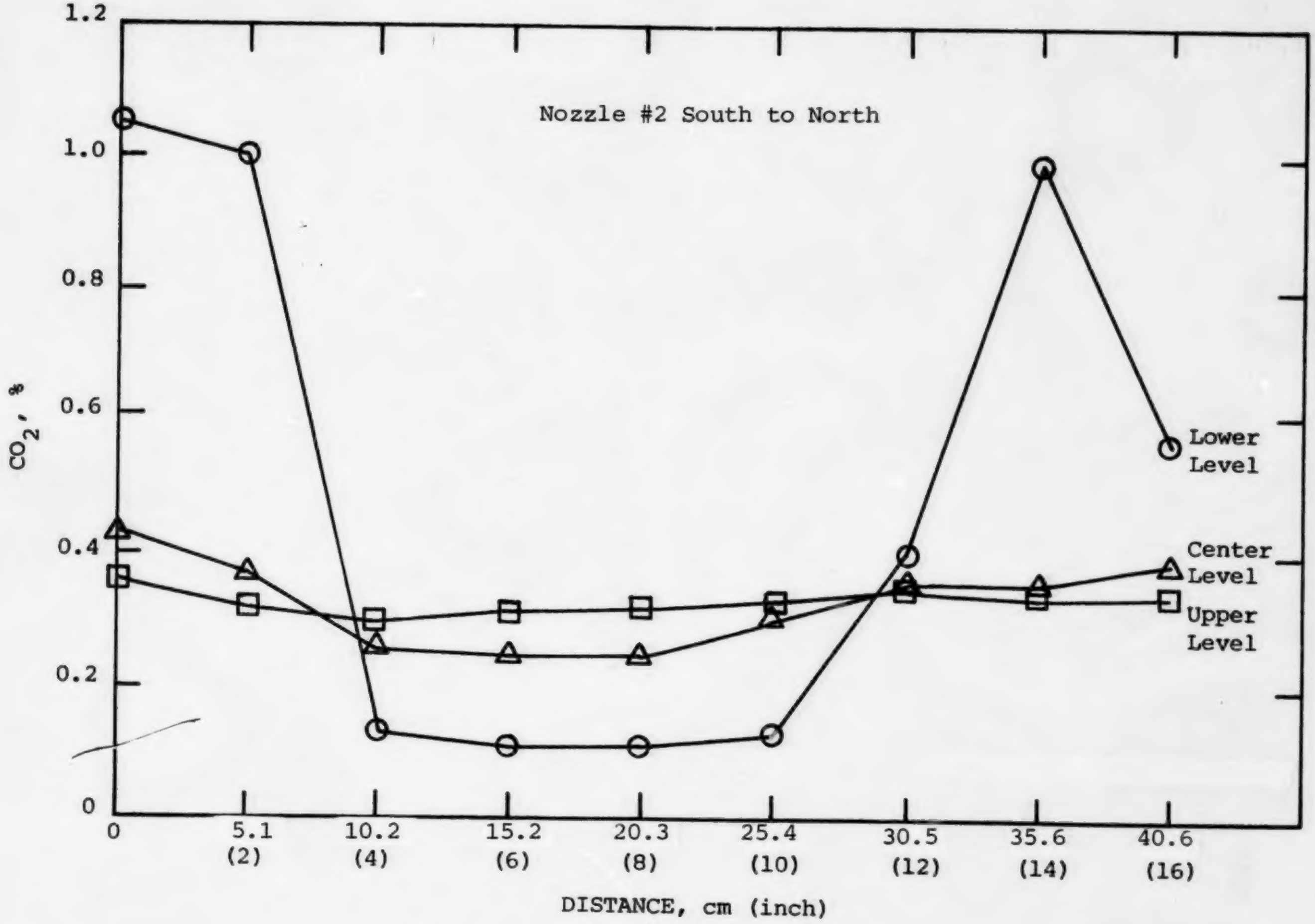

Figure 4-4. CO_2 concentration as a function of radial position for three axial positions.

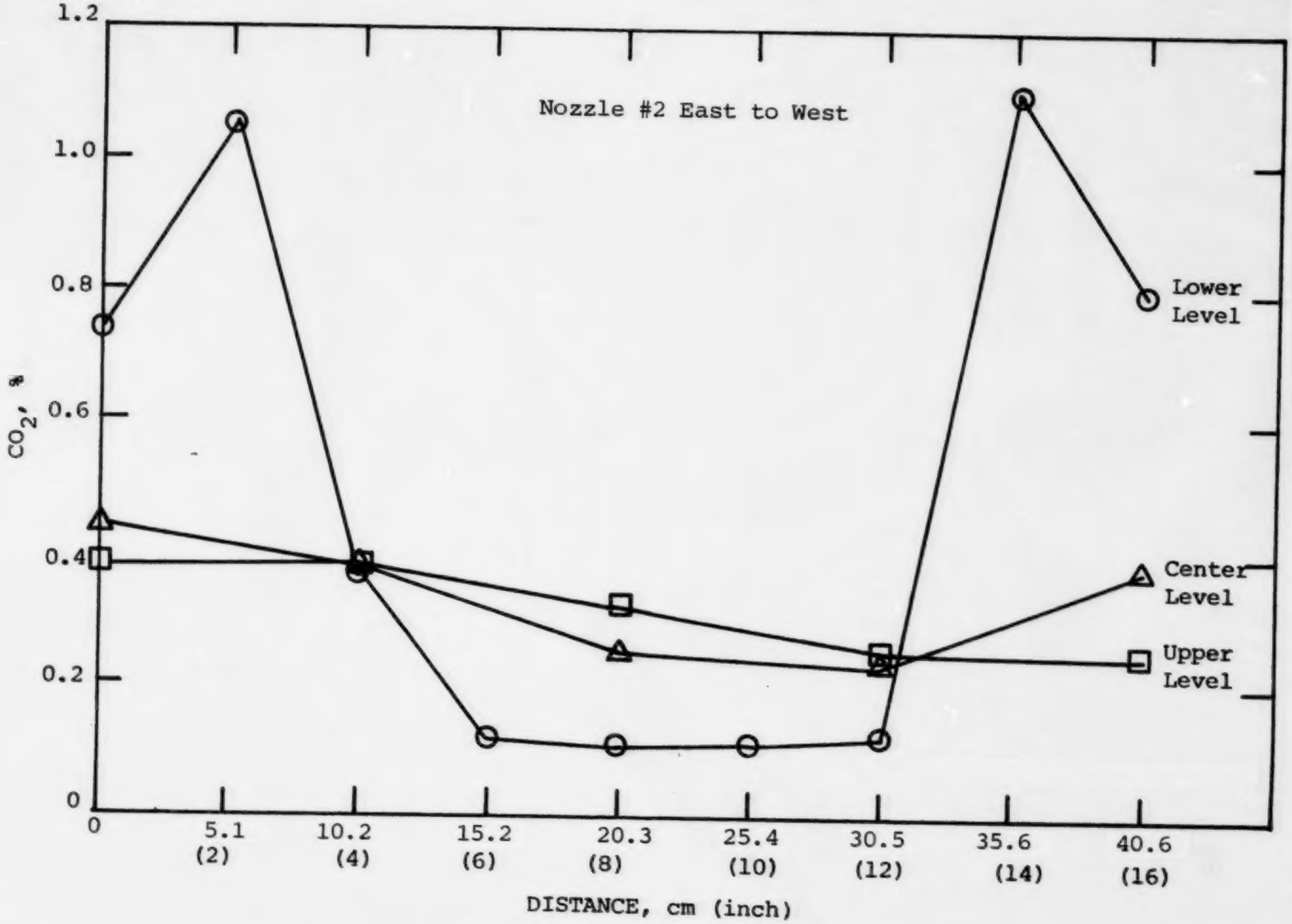

Figure 4-5. CO_2 concentration as a function of radial position for three axial positions.

Figure 4-4 shows the concentration gradient across the simulated burner for the three axial positions. The lower level, which is two inches above the gas injection plane, shows a large gradient in concentration. The high points are adjacent to the injection points. Inside the burner (10-20 cm, 4-10 inches) the fuel concentration is low. Examination of the center and upper level concentration curves shows that the gas is almost completely mixed within 36 cm (14 inches) of the burner. Figure 4-5 presents similar measurements made across the burner but at 90 deg. from the previous data. This figure shows similar trends, indicating that the burner mixing is uniform circumferentially.

Nozzles #3 and #4 injected fuel with a progressively greater tangential velocity component. (See Fig. 4-15 for a schematic of the three nozzle types. Note that Nozzle #3 here is actually the modified configuration II tip shown in that figure.) The mixing profiles of the three nozzles are compared in Figures 4-6 and 4-7. Figure 4-6 shows the concentration gradient at the burner exit plane for all three gas tips tested. Very little difference is noted among the three patterns. Figure 4-7 shows the concentration gradient 36 cm (14 in.) downstream from the injection plane for all three nozzles with only minor differences among the gas tip patterns.

Several modifications to the fuel injection geometry were evaluated with cold flow simulation. Modifications which looked promising from the cold flow model were then evaluated in the hot firing tests.

The modifications tested were the following:

1. Turning the gas nozzles so that the center firing port was aimed radially outward such that the gas stream impinged upon the 41 cm (16 in.) diameter cylindrical sleeve.
2. Placing a 20 cm (8 in.) diameter 'staging' cylinder whose vertical centerline coincided with that of the burner into the flow such that roughly 25%-30% of the 'combustion' air flow was introduced through the cylinder. Two cylinders of different length were used in separate tests. In one case, the top of the cylinder was 5.4 cm (2-1/8 in.) above the gas tips. In the second case, the cylinder top was 30.5 cm (12 in.) above the gas tips.

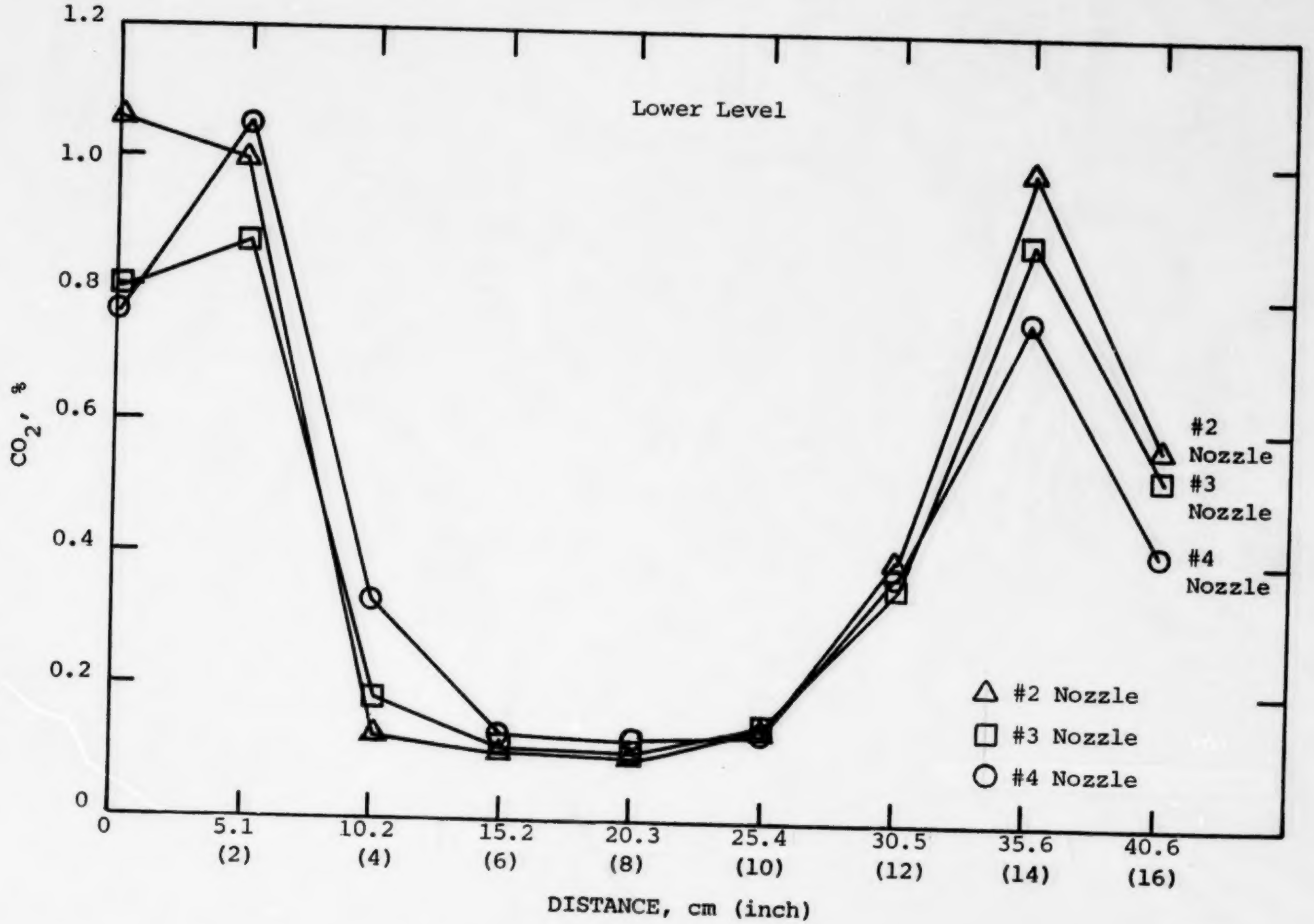

Figure 4-6. CO_2 concentration as a function of radial position for three gas tip patterns.

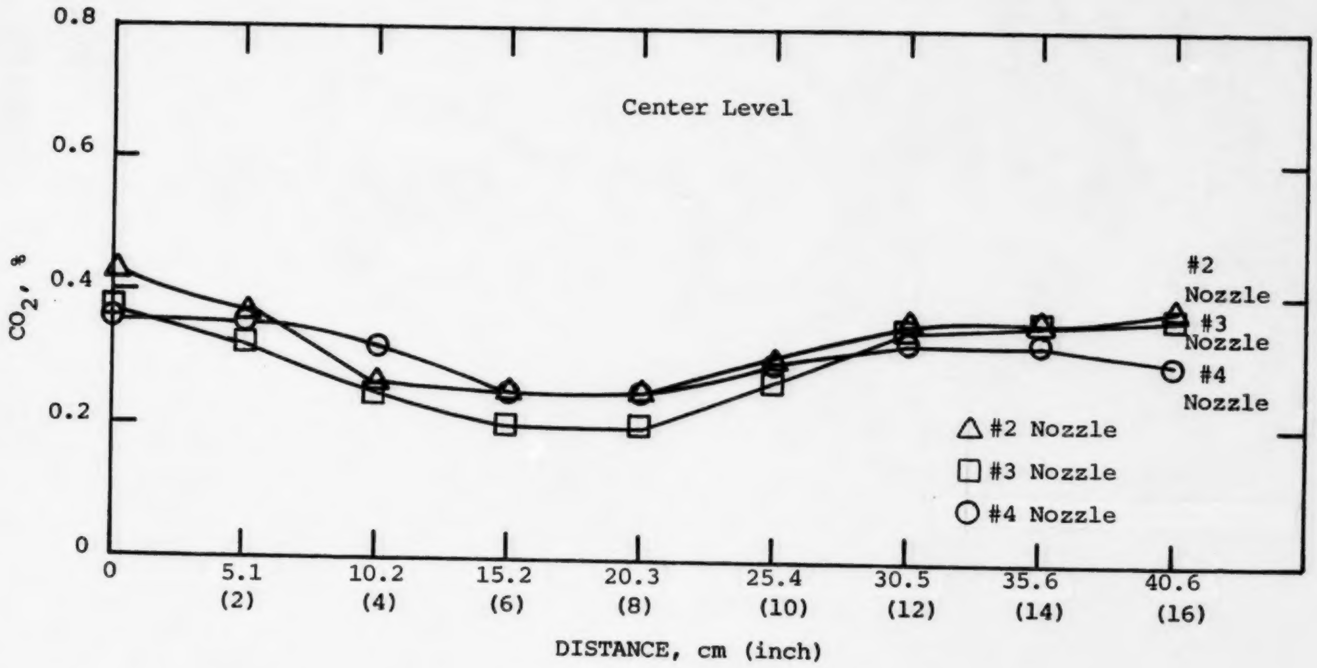

Figure 4-7. CO_2 concentration as a function of radial position for three gas tip patterns.

3. Placing a 7.6 cm (3 in.) wide, 15.2 cm (6 in.) long deflector upstream of each of the gas nozzles inclined at a 45-degree angle from vertical and extending from the 'burner' sleeve to the plane of the gas tip orifices.

All of these modifications were expected to delay mixing of fuel and air, thereby lengthening the flame in a hot-firing application, lowering peak temperatures and, thus, lowering NO_x emissions. The concentration of the cold flow test gas (CO_2) was measured at various positions along the north-south centerline across the simulated burner. The results for the four different test cases at each of three heights above the gas nozzles are shown in Figures 4-8, 4-9, and 4-10. These curves indicate that the concentric 'staging' cylinder and the radially-outward-facing injection orifices produce a significant delay in the mixing of the test gas and air. The mixing pattern with the deflectors in place did not vary appreciably from the patterns obtained for the nozzles without modification.

The mixing patterns of each of the three configurations which appear promising for hot-firing application are shown in Figures 4-11, 4-12, and 4-13. Based on these results, KVB made similar modifications to the conventional burner at the manufacturer's research facility.

4.3 HOT FIRING TEST RESULTS

Tests were conducted to evaluate the effect of combustion modifications on emissions from a natural draft process heater. The reduction in NO_x emissions and the change in efficiency were evaluated for (1) lowered excess air, (2) staged combustion air, (3) low-NO_x burners (tertiary air injection and recirculating tile designs), (4) flue gas recirculation, (5) steam injection and (6) altered fuel injection geometry. The tests were conducted with natural gas and No. 6 oil. Only burner baseline measurements were made with No. 2 oil. Fuel samples were taken for all tests, and the analyses are summarized in Table 4-1.

4.3.1 Baseline Tests

Tests were conducted with each burner prior to implementing any combustion modification. These baseline measurements were made with the burner firing natural gas, No. 6 oil, and No. 2 oil. A summary of baseline gaseous emissions data is presented in Table 4-2. A complete tabulation of all of the process heater test data is given in Appendix A.

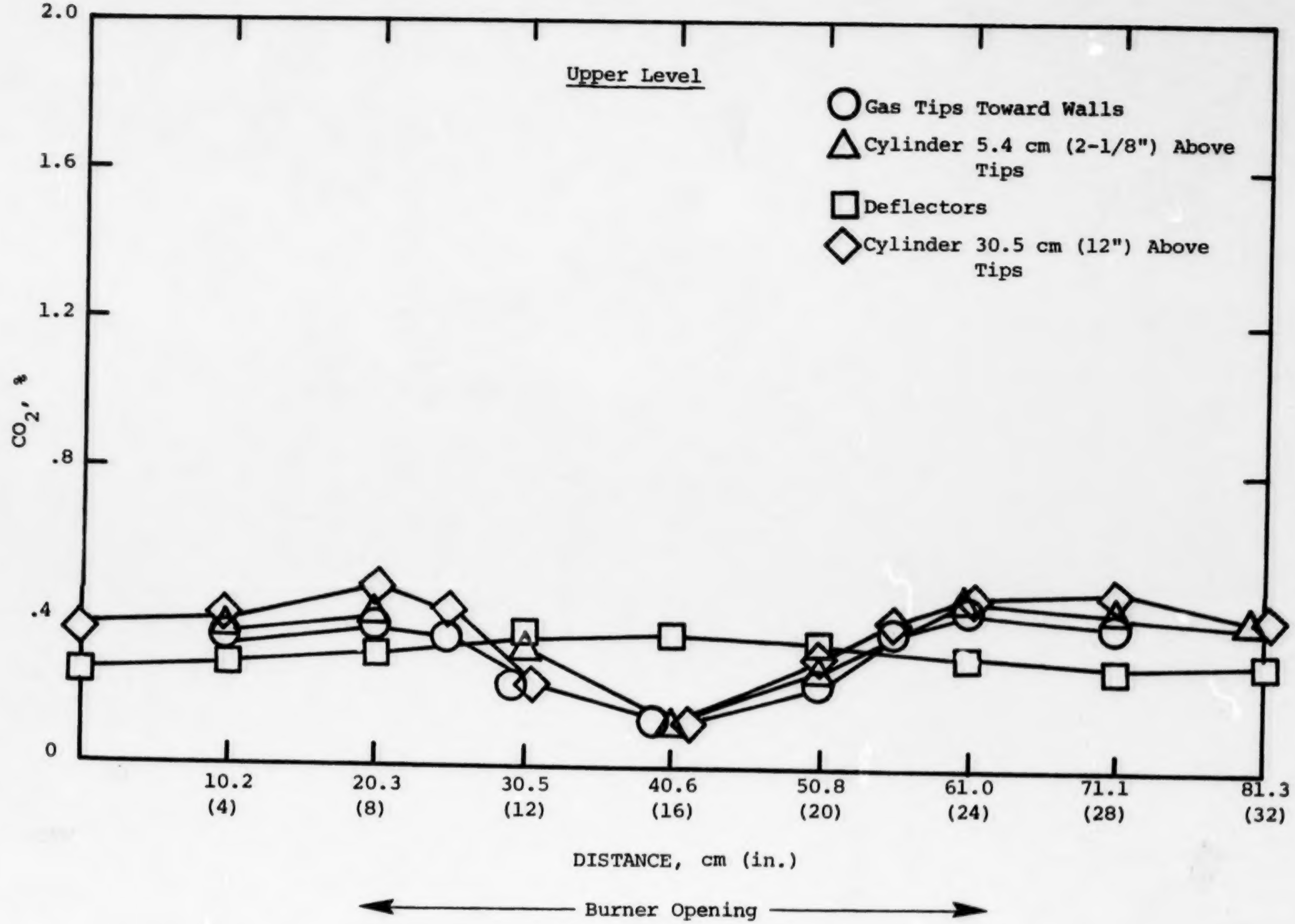

Figure 4-8. CO_2 concentration versus centerline distance at one axial position with four different modifications.

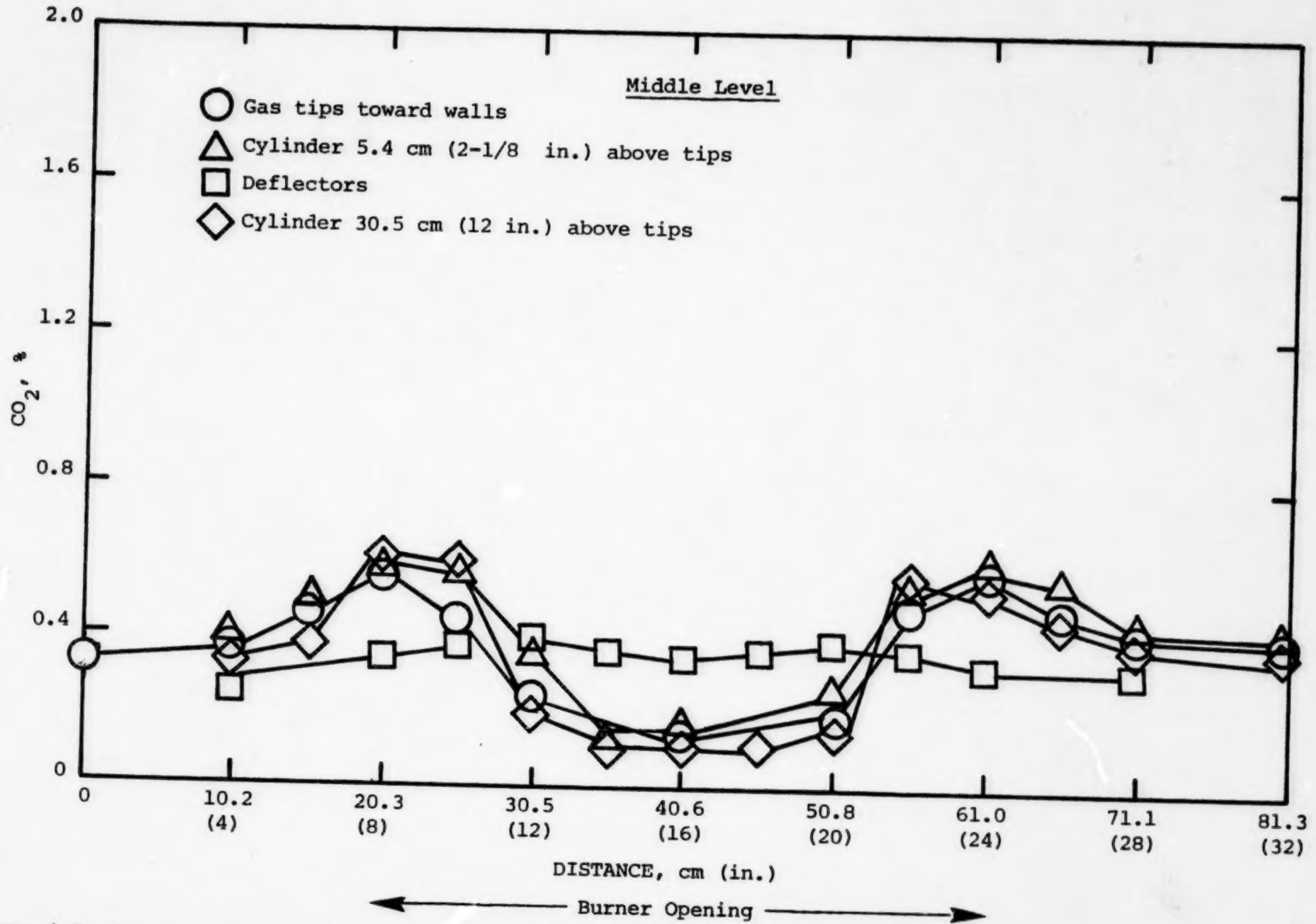

Figure 4-9. CO_2 concentration vs. centerline distance at one axial position with four different modifications.

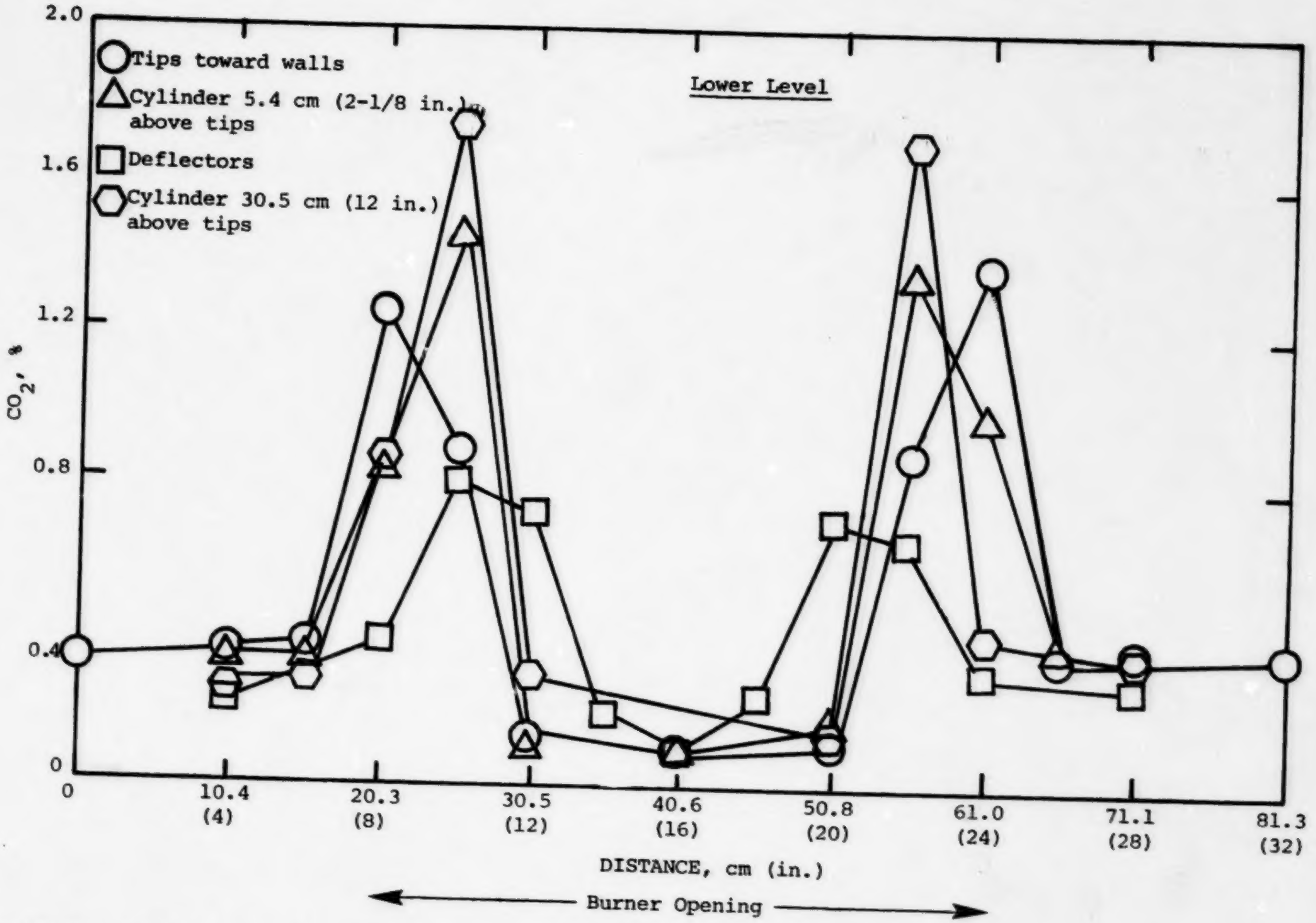

Figure 4-10. CO_2 concentration vs. centerline distance at one axial position with four different modifications.

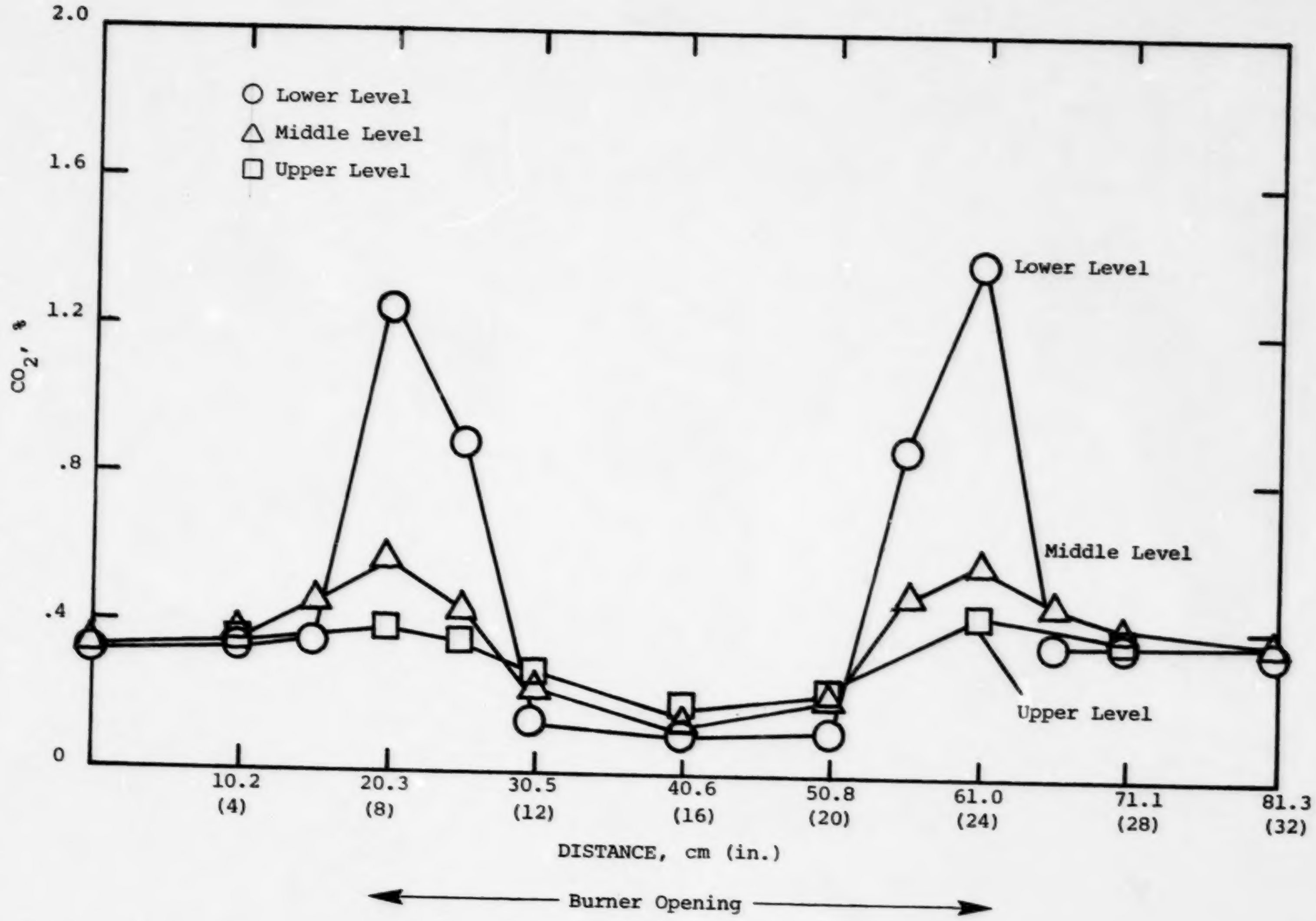

Figure 4-11. CO_2 concentration versus centerline distance at three axial positions with gas tip orifices turned toward walls.

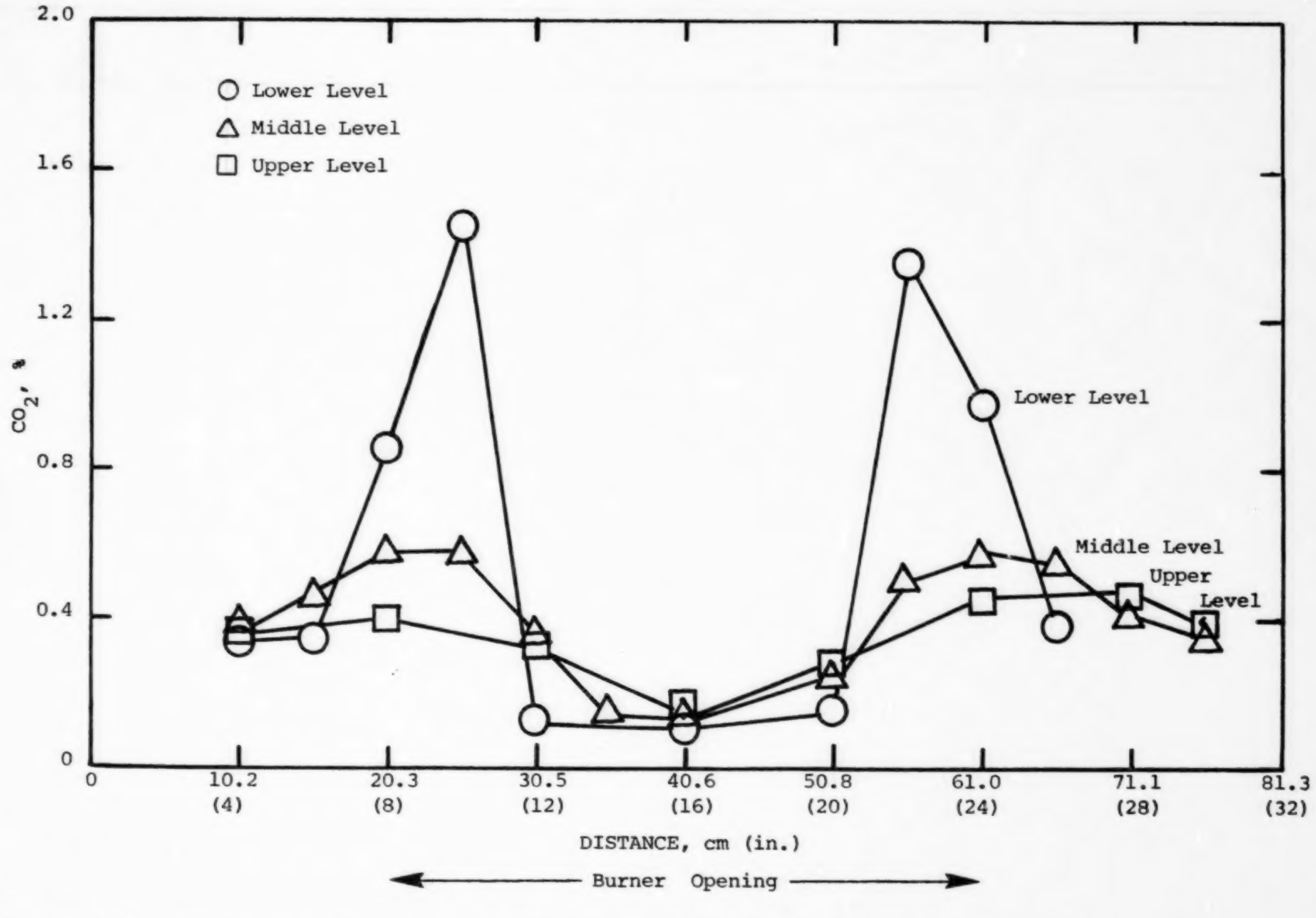

Figure 4-12. CO_2 concentration vs. centerline distance at three axial positions with cylinder top located 5.4 cm (2-1/8 in.) above gas tips.

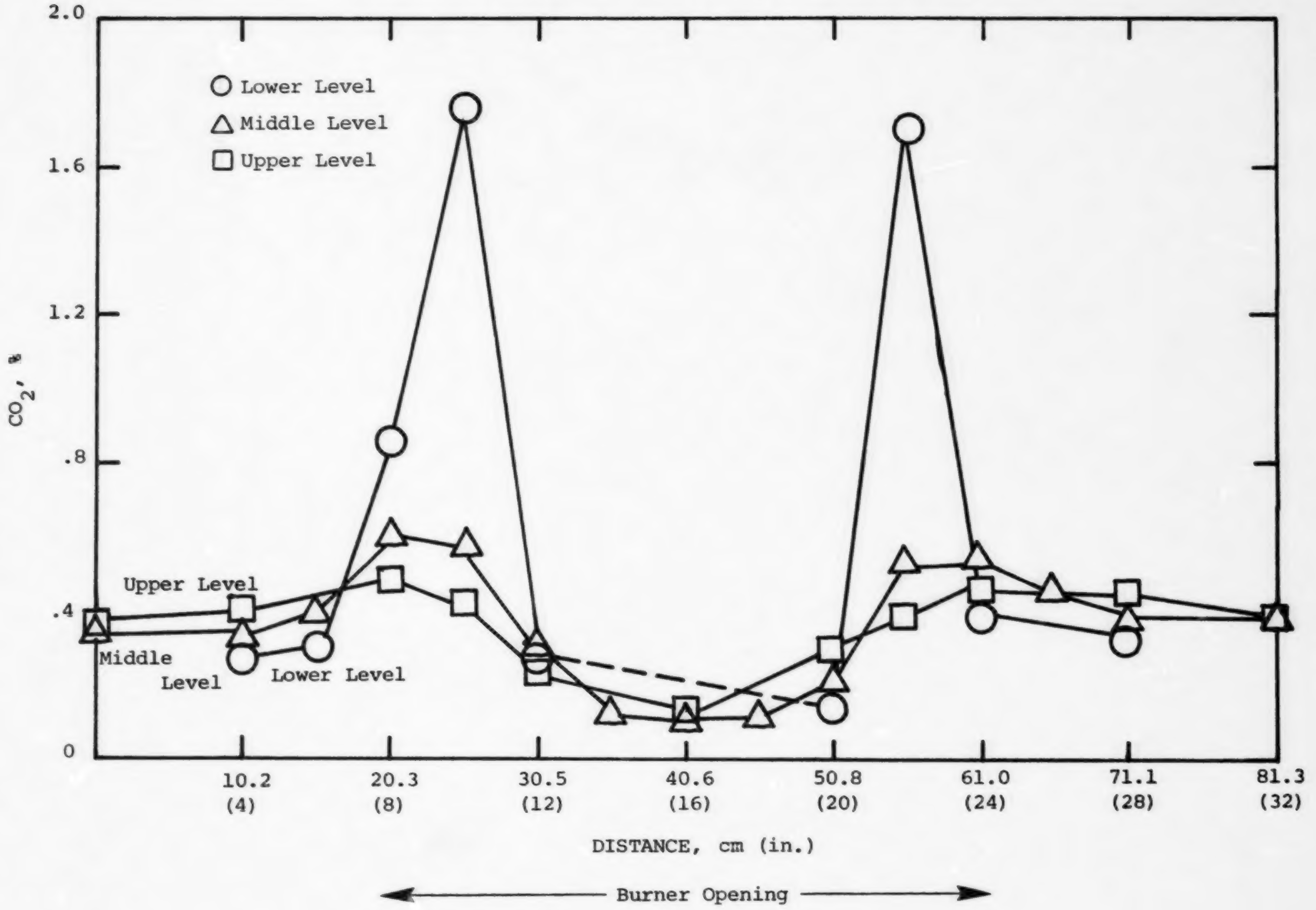

Figure 4-13. CO_2 concentration versus centerline distance at three axial positions with cylinder top located 30.5 cm (12") above gas tips.

TABLE 4-1. FUEL OIL AND NATURAL GAS ANALYSES

Fuel Oil

	1 No. 6 Oil, 1/18/78 Test 1/1-7	2 No. 2 Oil, 1/20/78 Test 1/1-10
Ultimate Analysis:		
Carbon, %	86.29	86.36
Hydrogen, %	10.07	13.48
Nitrogen, %	0.31	0.012
Sulfur, %	2.14	0.11
Ash, %	0.042	0.001
Oxygen, % (by difference)	1.15	0.04
API Gravity at 60 °F	11.4	38.7
Heat of Combustion:		
Gross, kJ/kg (Btu/lb)	42,082 (18,090)	45,688 (19,640)
Net, kJ/kg (Btu/lb)	39,942 (17,170)	42,827 (18,410)

Natural Gas

Component	Mol %
Helium	0.04
Nitrogen	2.23
Carbon Dioxide	0.53
Methane	92.14
Ethane	3.96
Propane	0.60
Iso-Butane	0.06
N-Butane	0.10
Iso-Pentane	0.03
N-Pentane	0.03
Hexane	0.03
Oxygen	0.25
Heating Value, dry, Gross, J/m^3 (Btu/CF)	38.18×10^6 (1025)
Specific Gravity of Gas (relative to air)	0.5987

Fuel Oil

	No. 6 Oil, 2/23/78	Shale Oil, 2/22/78
Carbon, %	85.98	83.96
Hydrogen, %	10.33	11.17
Nitrogen, %	0.31	2.10
Sulfur, %	2.18	0.52
Ash, %	0.042	0.051
Oxygen, % (by difference)	1.16	2.20
API Gravity at 60 °F	12.4	20.3
Heat of Combustion:		
Gross, kJ/kg (Btu/lb)	40,763 (18,190)	40,851 (18,270)
Net, kJ/kg (Btu/lb)	38,571 (17,250)	38,571 (17,250)

(continued)

TABLE 4-1 (Continued).

	Fuel Oil
	No. 6 Oil, 3/23/78
Carbon, %	85.37
Hydrogen, %	10.54
Nitrogen, %	0.28
Sulfur, %	1.87
Ash, %	0.037
Oxygen, % (by difference)	1.90
API Gravity at 60 °F	13.7
Heat of Combustion:	
Gross, kJ/kg (Btu/lb)	40,606 (18,120)
Net, kJ/kg (Btu/lb)	38,455 (17,160)

	Fuel Oil
	No. 6 Oil, 5/4/78
Carbon, %	86.57
Hydrogen, %	10.62
Nitrogen, %	0.29
Sulfur, %	1.92
Ash, %	0.037
Oxygen, % (by difference)	0.56
API Gravity at 60 °F	13.5
Heat of Combustion:	
Gross, kJ/kg (Btu/lb)	42,594 (18,310)
Net, kJ/kg (Btu/lb)	40,338 (17,340)

TABLE 4-2. SUMMARY OF AVERAGE BASELINE GASEOUS EMISSIONS FOR UNMODIFIED BURNERS

	Heat Input Rate		O_2	CO_2	NO_x		NO		CO	SO_2
	MW	(10^6 Btu/h)	%	%	ppm*	ng/J	ppm*	ng/J	ppm*	ppm*
Natural Gas										
MA-16	1.53	(5.2)	3.0	10.7	107	54.6	103	53.8	0	0
DBA-16	1.52	(5.2)	3.0	10.3	131	67.0	127	64.9	0	0
Low-NO_x Burner (Tertiary Air Injection)	1.49	(5.1)	3.2	10.4	92	47.1	87	44.4	0	0
Low-NO_x Burner (Recirculating Tile)	1.47	(5.0)	3.1	9.9	104	53.0	104	53.0	0	0
No. 6 Oil										
MA-16	1.47	(5.0)	3.0	13.3	285	159	278	156	0	1015
Low-NO_x Burner (Tertiary Air Injection)	1.43	(4.9)	3.1	13.7	265	149	261	147	0	1334
No. 2 Oil										
MA-16	1.41	(4.8)	3.1	12.7	112	63	108	61	0	46
Low-NO_x Burner (Recirculating Tile)	1.49	(5.1)	3.9	12.6	110	61.7	105	58.9	0	38

*Corrected to 3% O_2, dry

Initial tests were conducted with a standard MA-16 natural draft burner. A schematic (Fig. 4-14) of a section through the burner at the injection plane shows the relative position of the four natural gas tips. An oil gun was installed at the center of the burner. Three configurations of gas tips were evaluated with this burner. Details of the gas tip hole drill patterns are shown in Figure 4-15 for the three configurations tested. The modified configuration II tip and the configuration IV tip result in a more tangential injection of the gas jet.

4.3.2 Lowered Excess Air

The effect of burner operation at lowered excess air was evaluated for three unmodified burners--two standard natural draft burners and a low-NO_x burner design which incorporates tertiary air injection. The effect of stack oxygen on NO_x emissions is shown in Figure 4-16 for the three burners tested. The low-NO_x burner (tertiary air injection) exhibited the lowest level of NO_x at the nominal 3% O_2 condition and showed the most dependence on O_2 level. NO_x dropped sharply as O_2 decreased. The NO_x emissions at 2.7% O_2 were 100 ppm, which dropped off to 76 ppm at 2.1% O_2.

The effect of stack O_2 on NO firing No. 6 oil with three different spray patterns is shown in Figure 4-17 for the MA-16 natural draft burner.* The spray angle is defined as the total included angle of the conical jet produced by the oil gun. The effect of O_2 on NO emissions is not very pronounced over the range of O_2 tested. For the 30-deg. spray angle, the maximum NO reduction was 21% from the baseline condition. The minimum NO level was 222 ppm (at 3% O_2, dry) with the burner operating at 0.85% O_2, the CO limit. With the 40-deg. spray angle nozzle, the maximum reduction was 9% from the baseline condition. The minimum value for NO for this nozzle was

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*In some cases in this report, NO is graphed rather than NO_x. Generally, NO_2 accounted for less than 5% of the total NOx. In some instances only NO was measured so that a heated sample would not be required. In other cases, problems with the NO_2-to-NO converter section of the chemiluminescent analyzer precluded any measurement of NO_2. In any event, the difference between NO and total NO_x was generally small enough so that the values for each may be used interchangeably without introducing significant error.

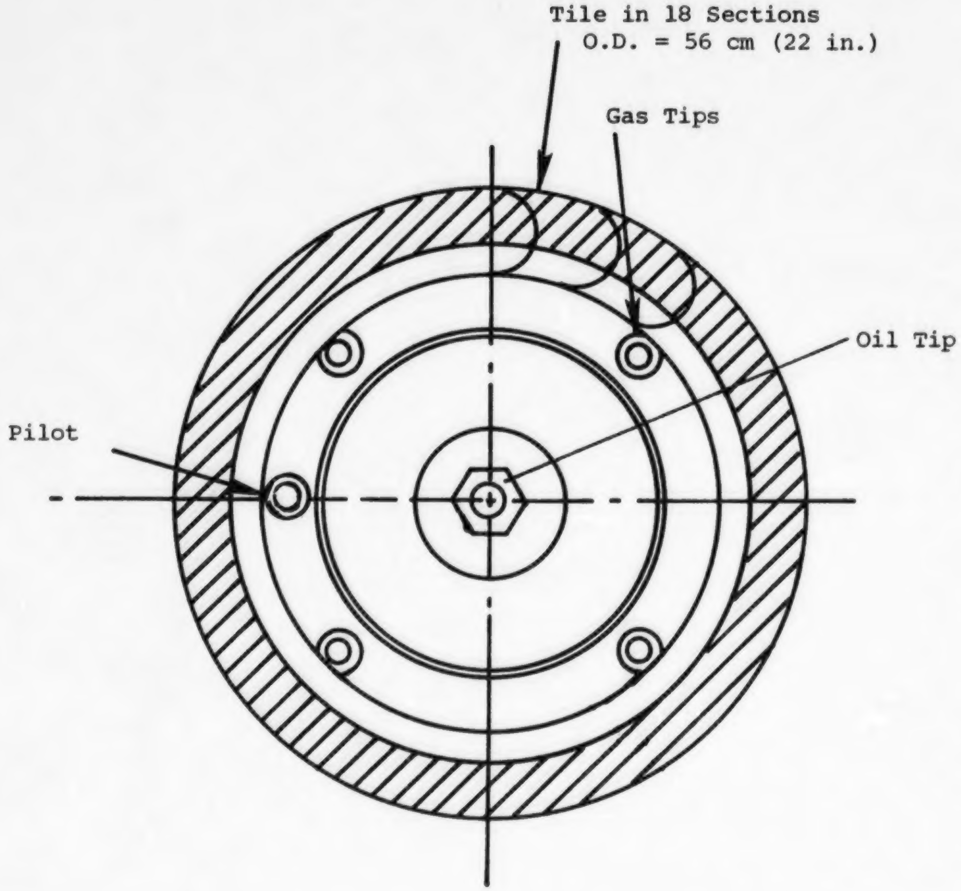
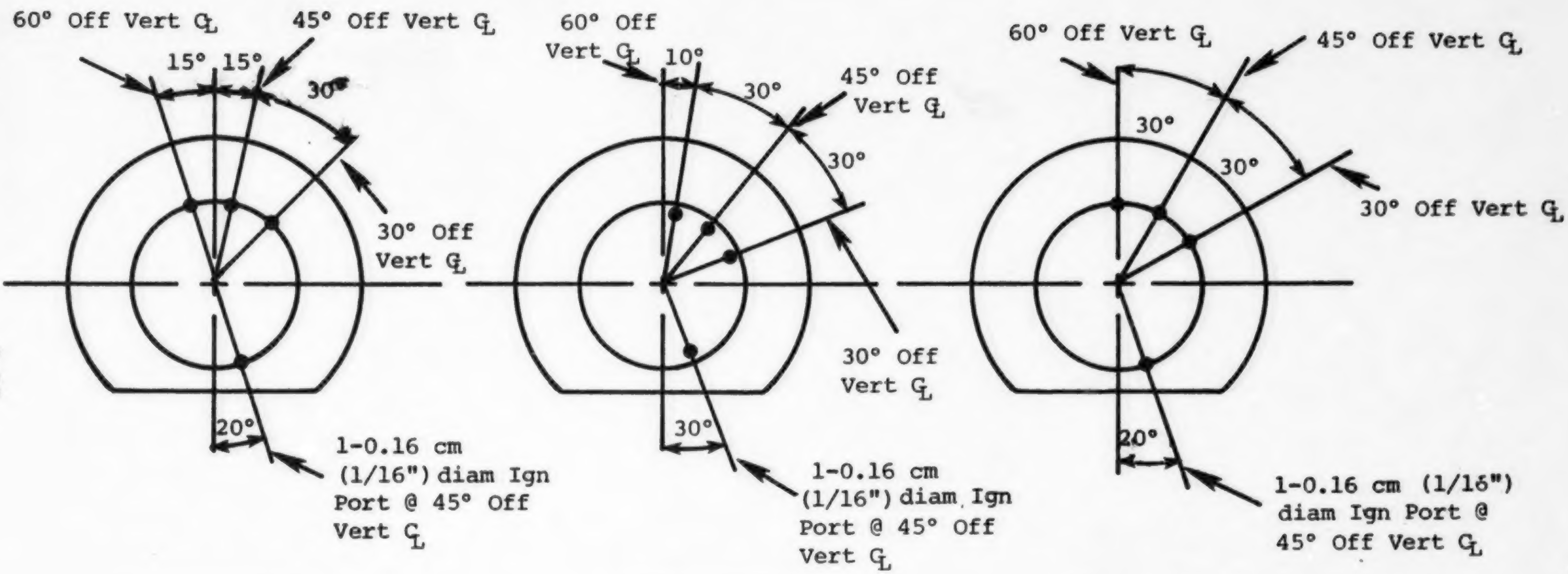

Tile in 18 Sections
O.D. = 56 cm (22 in.)
Gas Tips
Oil Tip
Pilot

Figure 4-14. Plan view of the MA-16 burner for natural draft process heater.


60° Off Vert ℄
45° Off Vert ℄
15° 15°
30°
30° Off Vert ℄
20°
1-0.16 cm (1/16") diam Ign Port @ 45° Off Vert ℄
60° Off Vert ℄
10°
30°
45° Off Vert ℄
30°
30° Off ℄
30°
1-0.16 cm (1/16") diam Ign Port @ 45° Off Vert ℄
60° Off Vert ℄
45° Off Vert ℄
30°
30°
30° Off Vert ℄
20°
1-0.16 cm (1/16") diam Ign Port @ 45° Off Vert ℄

CONFIGURATION II

CONFIGURATION IV

CONFIGURATION II (MODIFIED)

Figure 4-15. Gas tip hole drilling patterns. Note that vertical centerline is perpendicular to the plane of the page.

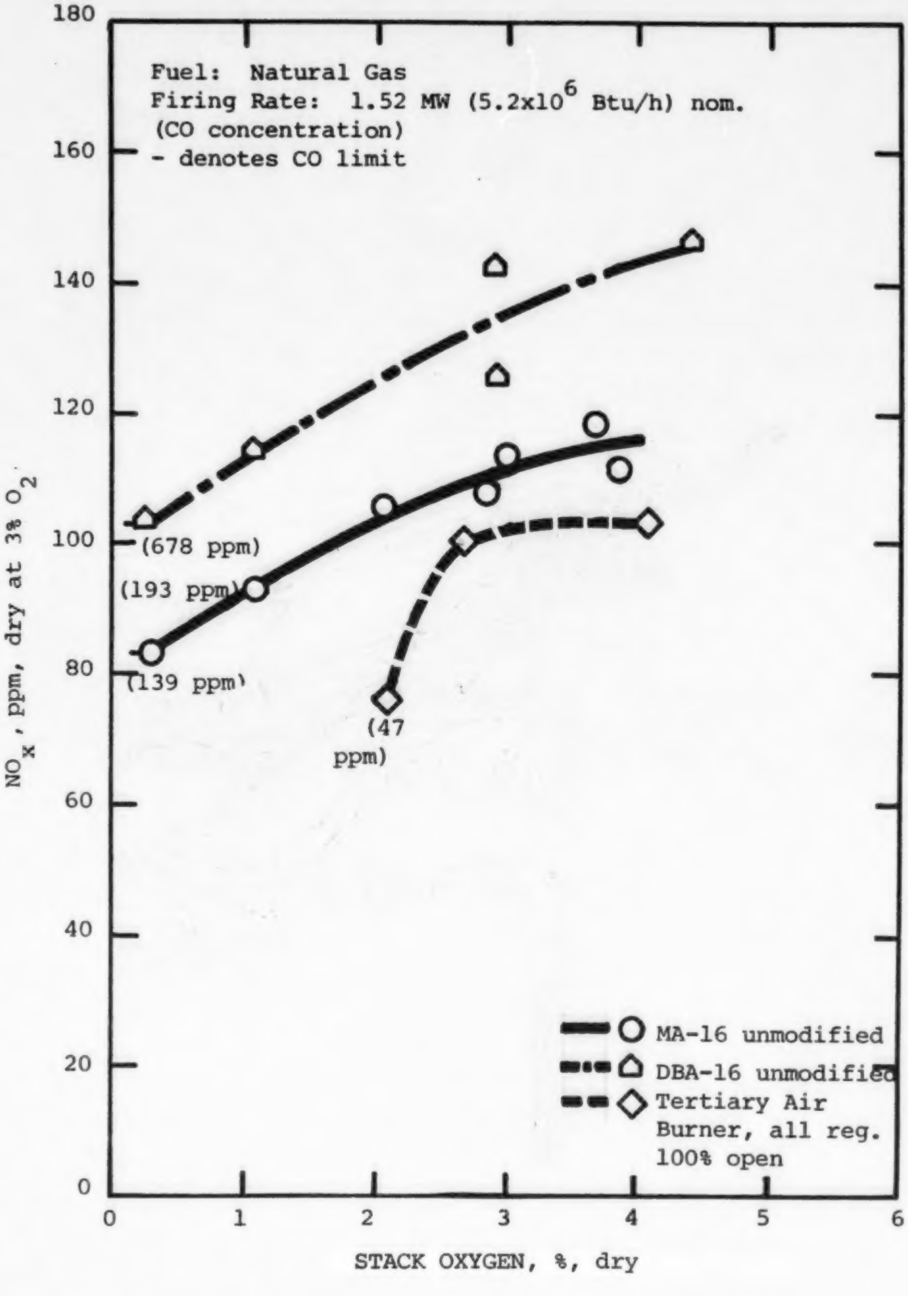


Figure 4-16. Summary of NO_x emissions as a function of stack oxygen for subscale natural draft furnace firing natural gas.

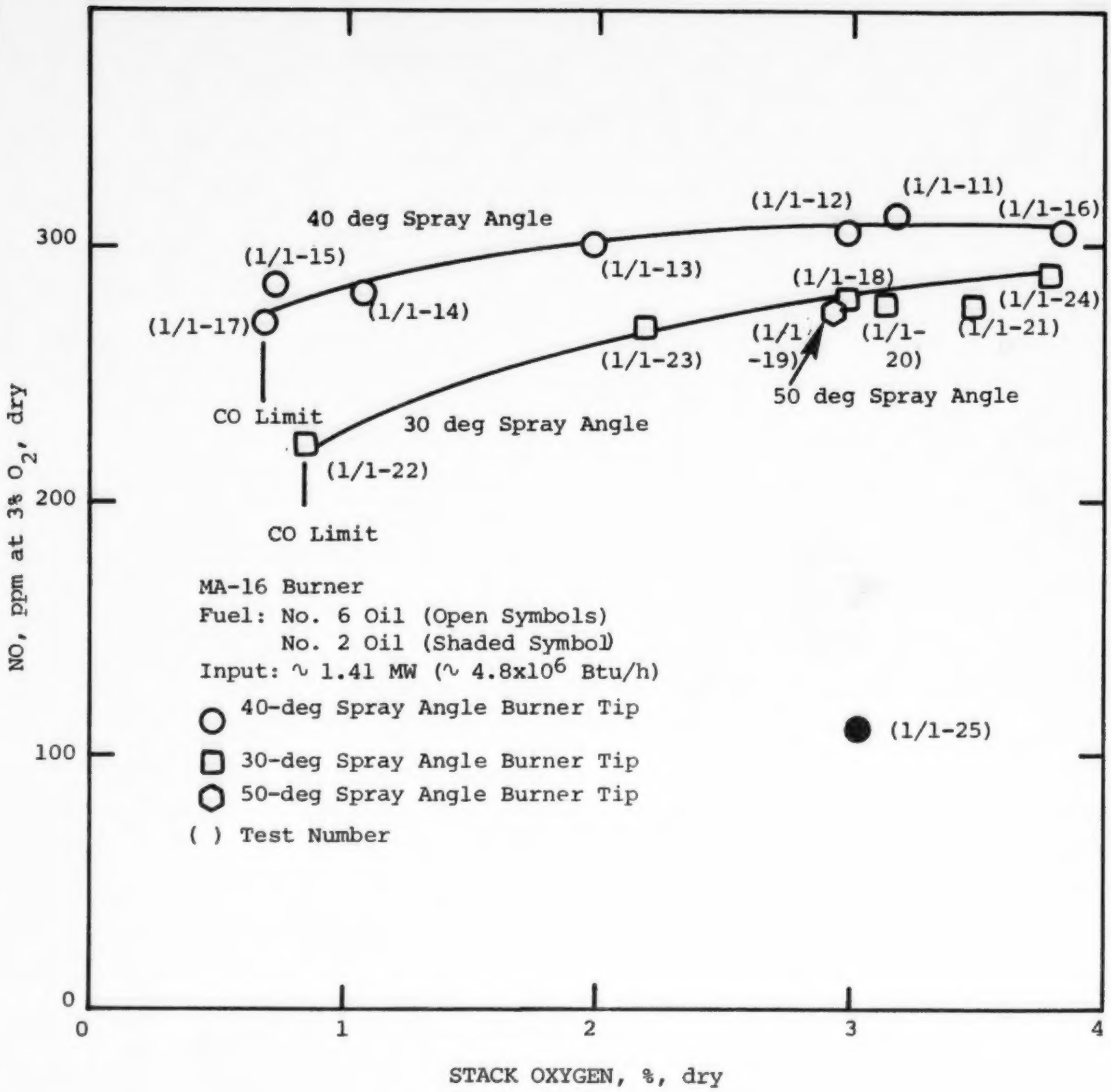


Figure 4-17. The effect of stack oxygen on NO emissions for a natural draft burner firing oil.

282 ppm (3% O_2, dry) at 0.75% O_2. The 50-deg. nozzle produced an NO measurement comparable to the 30-deg. nozzle but the flame appearance was very bad; it was impinging on refractory tiles, producing sparks, and smoking, and was very non-uniform. No further testing was conducted with the 50-deg. nozzle.

The baseline NO emission for the MA-16 burner firing No. 2 oil using a 40-deg. nozzle is also shown in Figure 4-17 for the sake of comparison.

4.3.3 Staged Combustion

Staged combustion is a technique for emissions reduction wherein a portion of the flame zone is operated fuel-rich, and secondary air is injected subsequently to bring the overall air-fuel ratio to the desired level to assure complete combustion. Staged combustion has been shown to be an effective method of NO_x reduction in other applications. In order to develop staged combustion in a natural draft heater, two techniques were evaluated. In the first method, four staged air lances were inserted through the furnace floor positioned 90 degrees apart outside the burner tile on a diameter of 61 cm (24 inches). This modification is shown schematically in Figure 4-18. The staged air lances were fabricated from 3.2 cm (1-1/4 in.) diameter stainless steel pipe with an orifice plate of 3.0 cm (1-3/16 in.) diameter on the end. The end of the lance was angled 45 degrees inward to provide better penetration of the flame by the secondary air. Adjustment of the insertion depth was provided by a locking collar outside the furnace floor. Adjustment in depth up to 1.52 m (5 ft) was possible. An MA-16 burner was used for these tests.

Nineteen tests were conducted with the staged air configuration to evaluate the effect on NO emissions and burner performance. Nine tests were with natural gas, and the remaining 10 were with No. 6 fuel oil. The first tests with natural gas consisted of varying the injection depth for the staged air. The effect of staged air injection depth on NO emissions is shown in Figure 4-19 for natural gas firing. Combustion air was held constant and the injection depth varied for tests 1/6-1 through 1/6-5. These data show that no significant reduction in NO_x is experienced with injection beyond 1.22 m

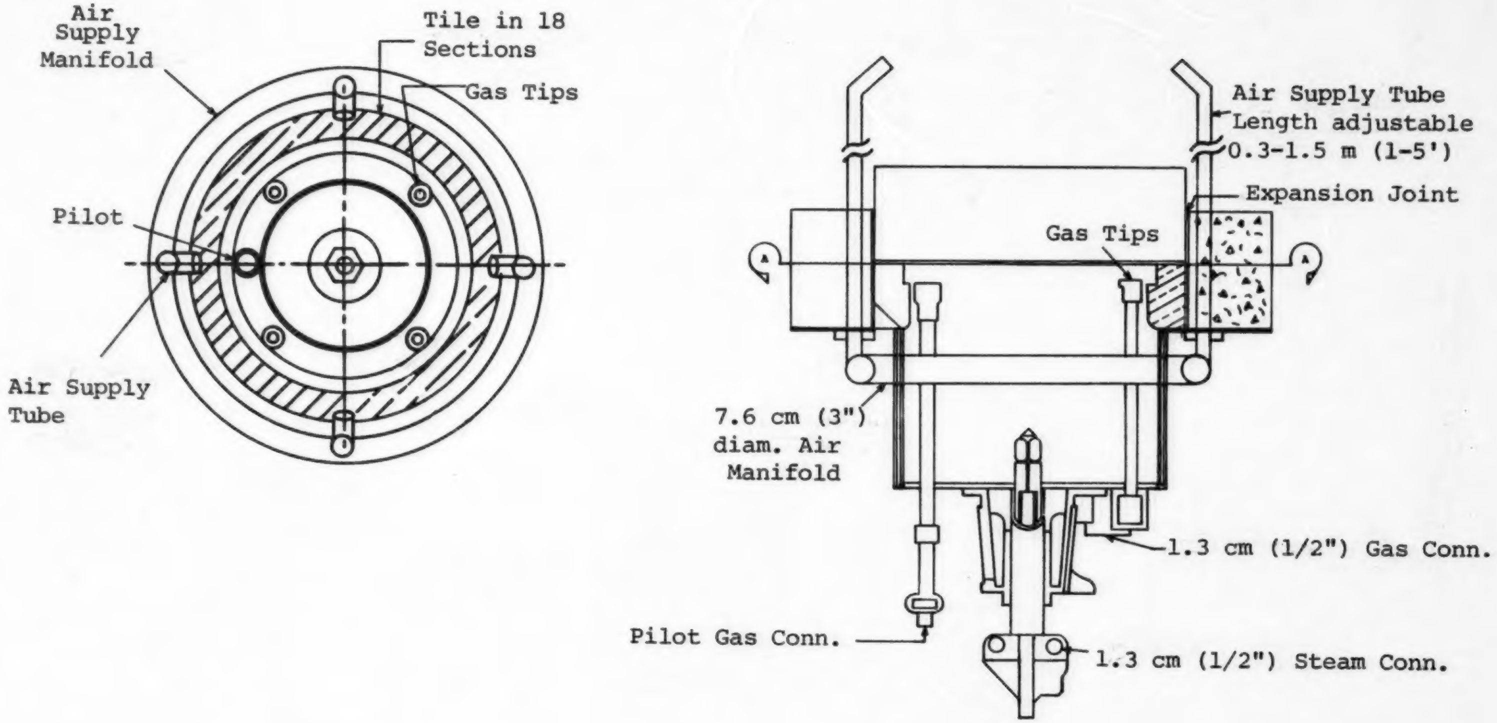

Air Supply Manifold
Tile in 18 Sections
Gas Tips
Pilot
Air Supply Tube
Air Supply Tube Length adjustable 0.3-1.5 m (1-5')
Expansion Joint
Gas Tips
7.6 cm (3") diam. Air Manifold
1.3 cm (1/2") Gas Conn.
Pilot Gas Conn.
1.3 cm (1/2") Steam Conn.

Figure 4-18. Schematic of staged combustion burner.

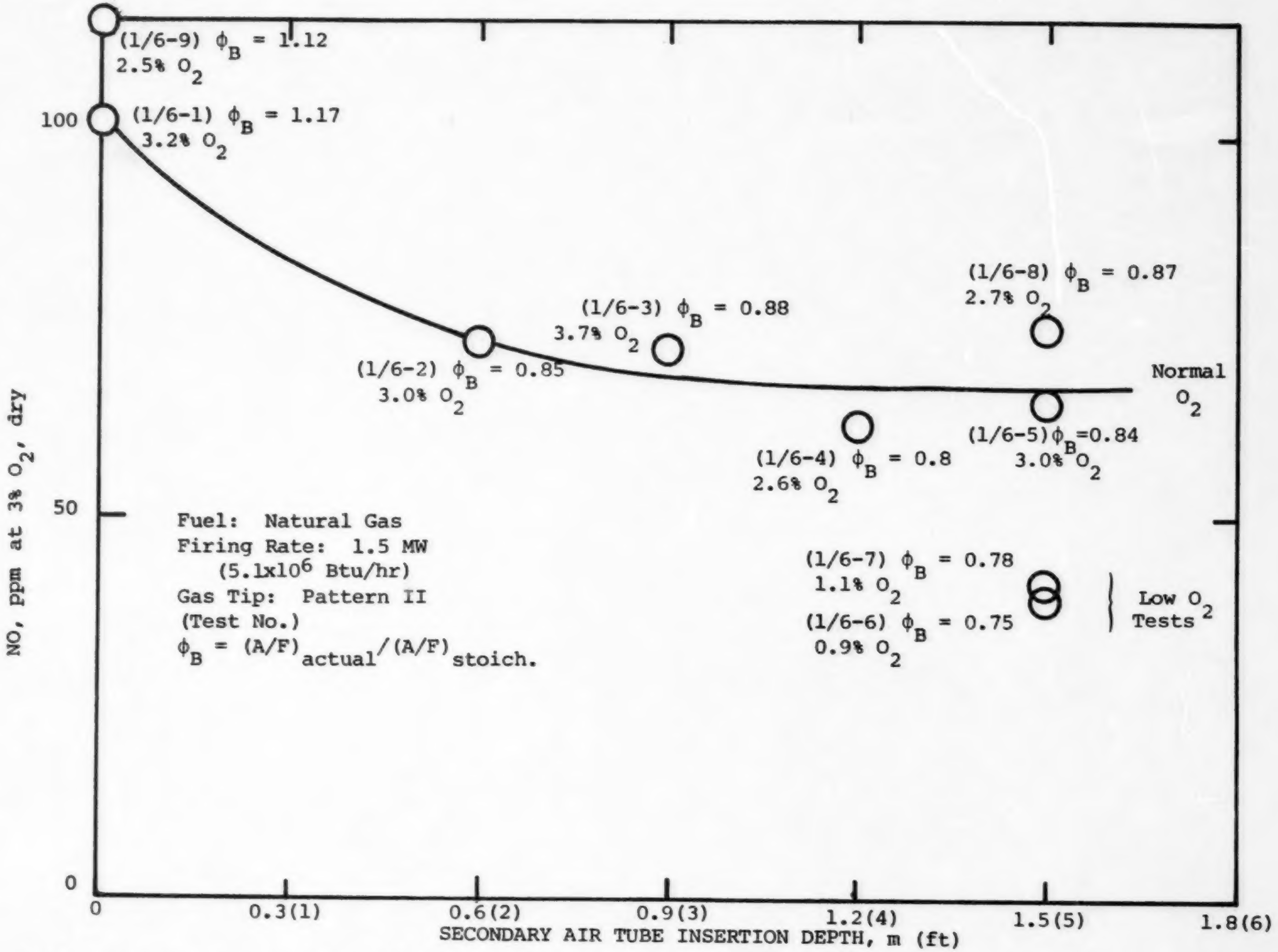


Figure 4-19. NO emissions as a function of staged air injection depth and burner air for natural gas firing.

(4 ft) approximately. With the staged air tubes at the maximum depth of 1.52 m (5 ft), the stack oxygen was reduced to 0.9% O_2, which was the CO limit. The combination of low O_2 and staged combustion air gave the maximum reduction of 67%.

The effect of the burner air-to-fuel ratio is shown in Figure 4-20 for natural gas firing. The parameter ϕ is the ratio of actual air-fuel ratio to stoichiometric air-fuel ratio. Values of $\phi < 1$ indicate the burner was operating fuel-rich.

The staged combustion modification was also evaluated with the burner firing No. 6 fuel oil. The staged air lances were at a fixed insertion depth of 1.22 m (4 ft) for all tests with oil. The effect of burner ϕ on NO_x emissions is shown in Figure 4-21. At the normal O_2 condition, a reduction of 35% was achieved. With unit operating in the low O_2 mode a reduction of 51% from the baseline condition was achieved.

An alternative method of producing staged combustion was developed from the cold flow tests described in an earlier section. This technique employed a central cylinder which introduced the secondary air into the flame zone after the primary combustion zone.

Figure 4-22 illustrates the staging cylinder concept based on cold flow model work. For this modification the orifice plate was removed from a DBA-16 burner (a conventional burner differing only in tile design from the MA-16 burner) and a 19.1 cm (7-1/2 in.) I.D., 21.6 cm (8-1/2 in.) O.D. cylinder placed in the burner such that its longitudinal axis coincided with the vertical centerline of the burner. The bottom of the cylinder rested on the base of the secondary air section of the burner. Thus, all of the primary air flow (approximately 1/3 of the total air flow) was routed through the cylinder and the rest through the secondary air registers.

The staging cylinder concept was tested in the KVB cold flow model and demonstrated to be effective in delaying mixing of fuel gas and air in the model and was expected to lower NO_x emissions under actual operating conditions. The effect of the cylinder is to produce fuel-rich zones in the vicinity of the gas tips and relatively lean regions further downstream.

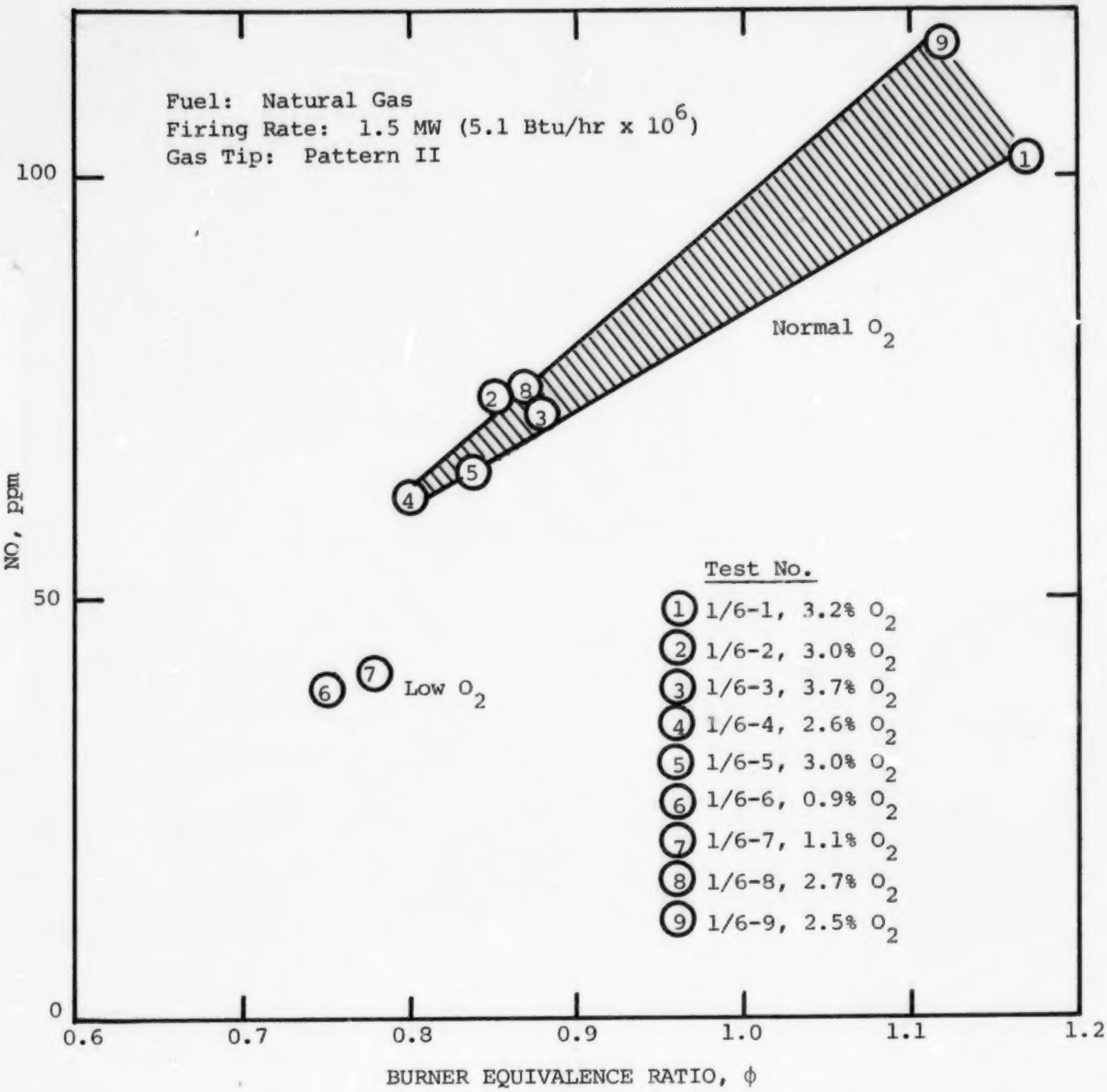


Figure 4-20. NO emissions as a function of burner equivalence ratio ($\phi \equiv (A/F)_{actual}/(A/F)_{stoich}$).

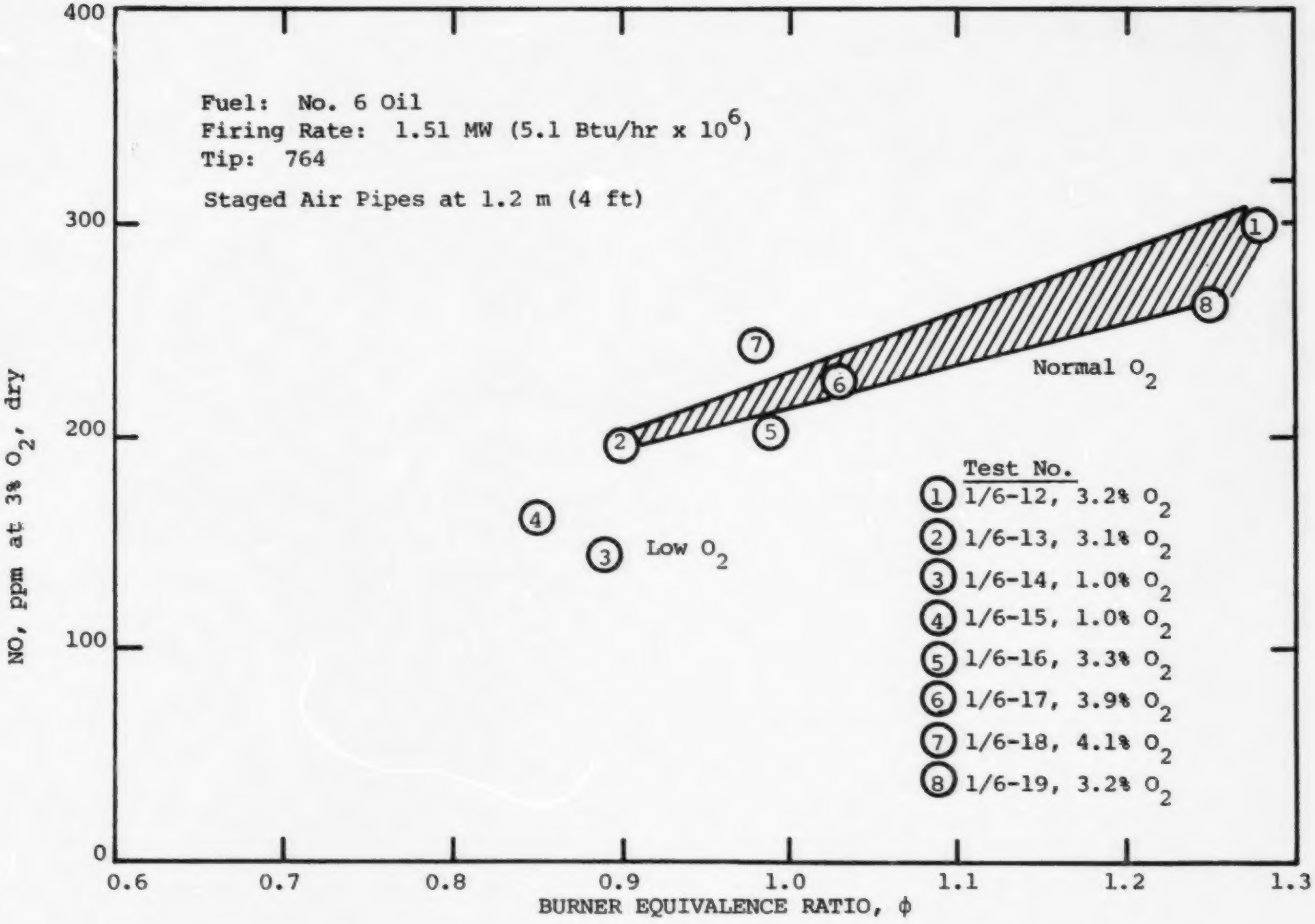


Figure 4-21. NO emissions as a function of burner ϕ for No. 6 oil firing.

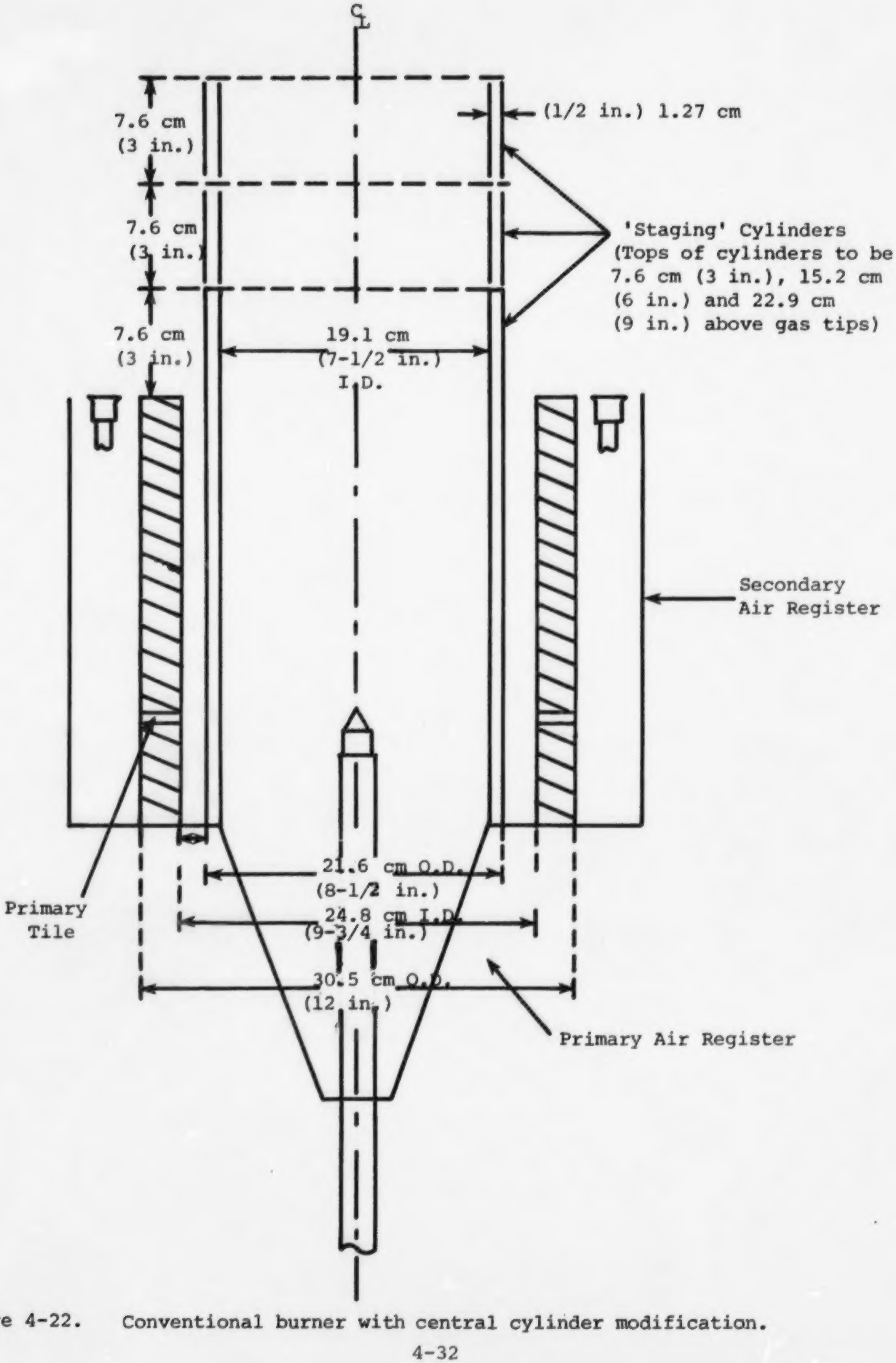

C
L
7.6 cm
(3 in.)
7.6 cm
(3 in.)
7.6 cm
(3 in.)
(1/2 in.) 1.27 cm
'Staging' Cylinders
(Tops of cylinders to be
7.6 cm (3 in.), 15.2 cm
(6 in.) and 22.9 cm
(9 in.) above gas tips)
19.1 cm
(7-1/2 in.)
I.D.
Secondary
Air Register
21.6 cm O.D.
(8-1/2 in.)
24.8 cm I.D.
(9-3/4 in.)
30.5 cm O.D.
(12 in.)
Primary
Tile
Primary Air Register

Figure 4-22. Conventional burner with central cylinder modification.

Several different cylinder lengths were tried in this series of tests. The height of the top of the cylinder above the gas tips was varied from 7.6 cm (3 in.) to 109 cm (43 in.). Figure 4-23 summarizes the NO_x emissions from a DBA-16 burner equipped with different staging cylinder lengths for approximately 3% O_2. The graph suggests that an optimum height above the gas tips lies between 23 cm (9 in.) and 94 cm (37 in.). The lowest NO_x emissions of the cylinder heights tested occurred at 94 cm (37 in.) above the gas tips and was 88 ppm, down 33% from the standard DBA-16 burner average baseline of 131 ppm.

At a cylinder height of 109 cm (43 in.), stack oxygen was varied from 4.9% to the CO limit of 0.5% (with a CO concentration of 439 ppm). At 1.2% O_2, the NO_x concentration was 66 ppm, a reduction of 42% from the corresponding O_2 point for the standard DBA-16 burner. At the CO limit, the NO_x level dropped to 54 ppm for a reduction of 48% from the CO limit concentration emitted by the standard burner. Figure 4-24 shows the variation of NO_x concentration with stack O_2 for this cylinder height.

4.3.4 Low-NO_x Burner (Tertiary Air Injection)

A low-NO_x burner similar to the conventional MA-16 burner was tested. This low-NO_x design incorporated a tertiary air register above the primary and secondary air registers. Figure 4-25 is an overall schematic of the tertiary air burner, and Figure 4-26 is a plan view of the burner.

The tertiary air register allows a certain amount of staging of the combustion process. Under ordinary operating conditions all registers are 100% open, and 60% of the burner air flow comes through the primary and secondary air registers while 40% of the air comes through the tertiary air register. The tertiary air is introduced in an annular ring outside the primary and secondary air flows. Normally, the primary and secondary air registers communicate, but for the purposes of these tests, they were banded off so that each air stream could be independently varied.

Figure 4-27 shows the gas tip hole drilling patterns used in the tertiary air burner for tests with natural gas. For the first pattern tried (Configuration IIB), NO_x levels were high. Baseline emission was 153 ppm (corrected to 3% O_2, dry).

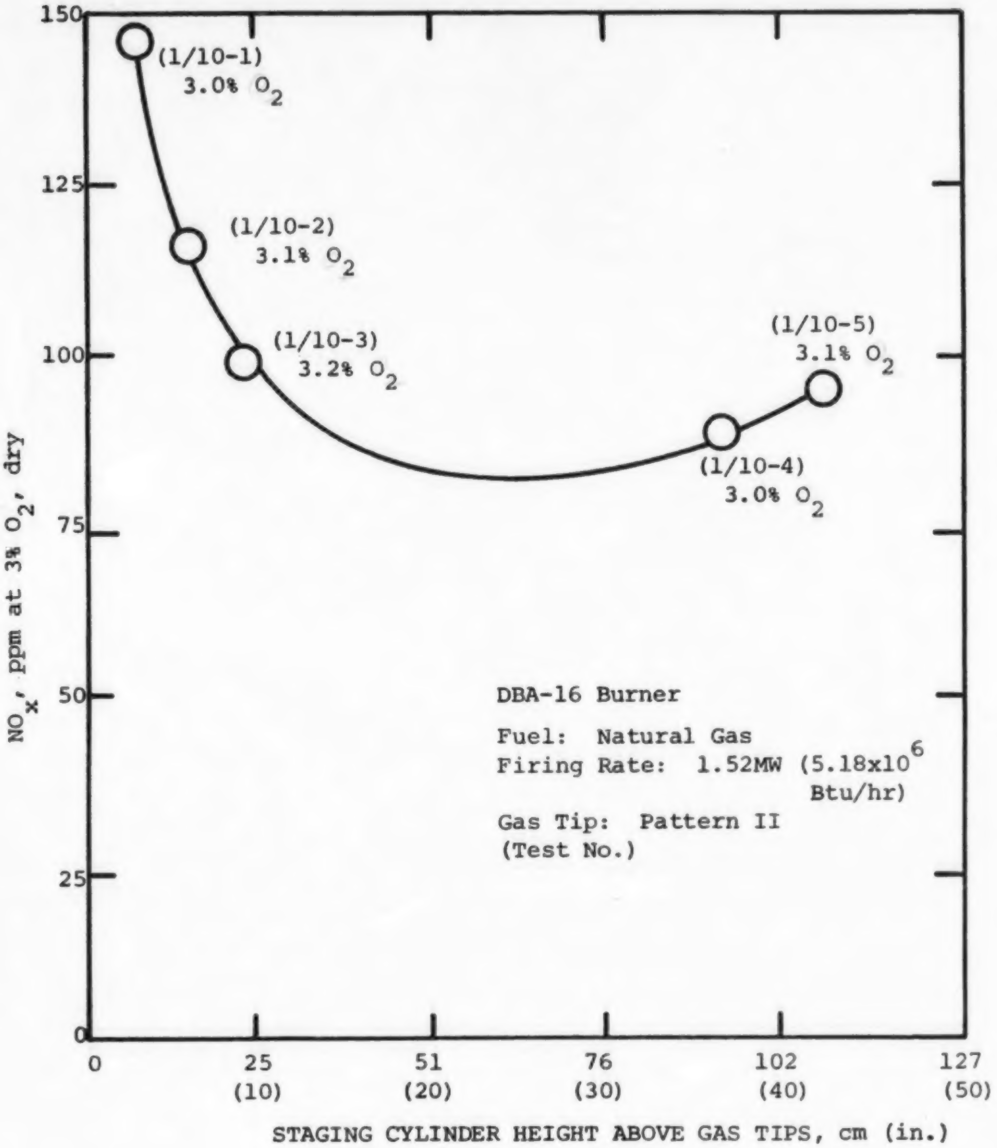


Figure 4-23. NO$_x$ emission as a function of staging cylinder height above gas tips.

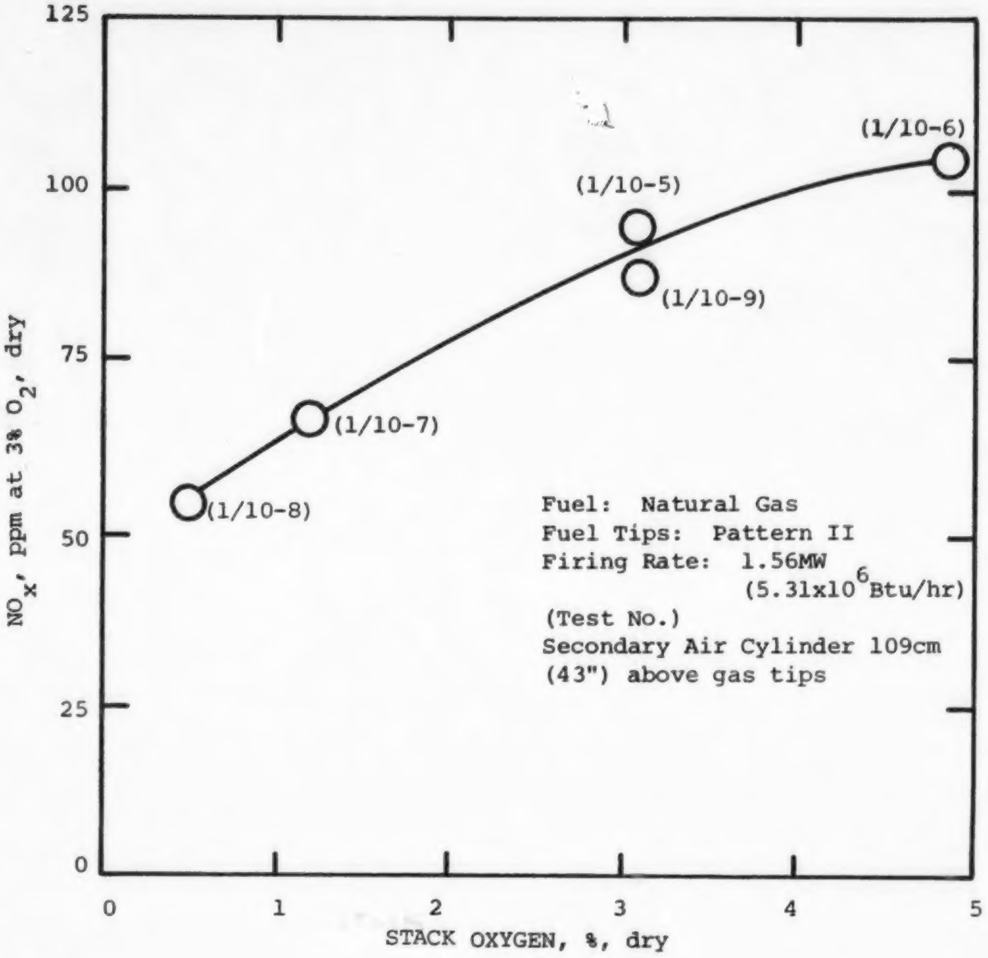


Figure 4-24. NO$_x$ emissions as a function of stack oxygen while firing natural gas.

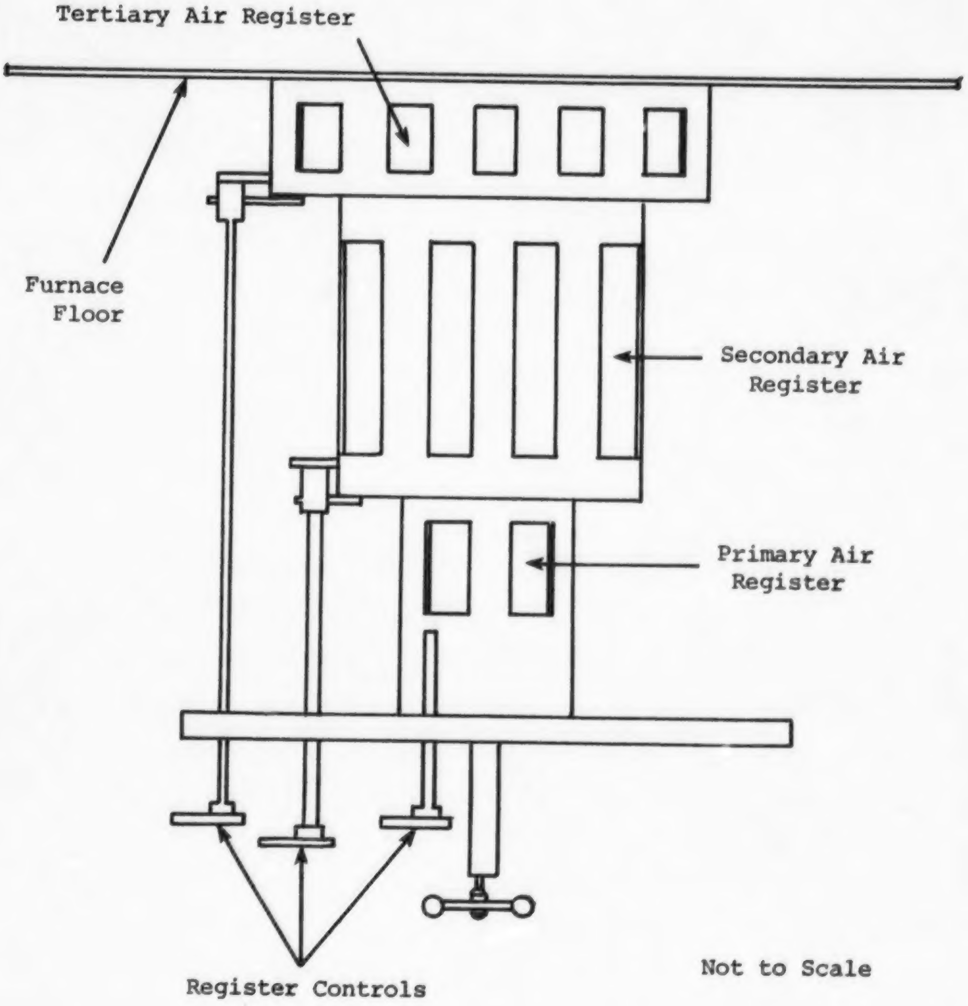

Tertiary Air Register
Furnace Floor
Secondary Air Register
Primary Air Register
Register Controls
Not to Scale

Figure 4-25. Schematic of tertiary air burner for natural draft process heater.

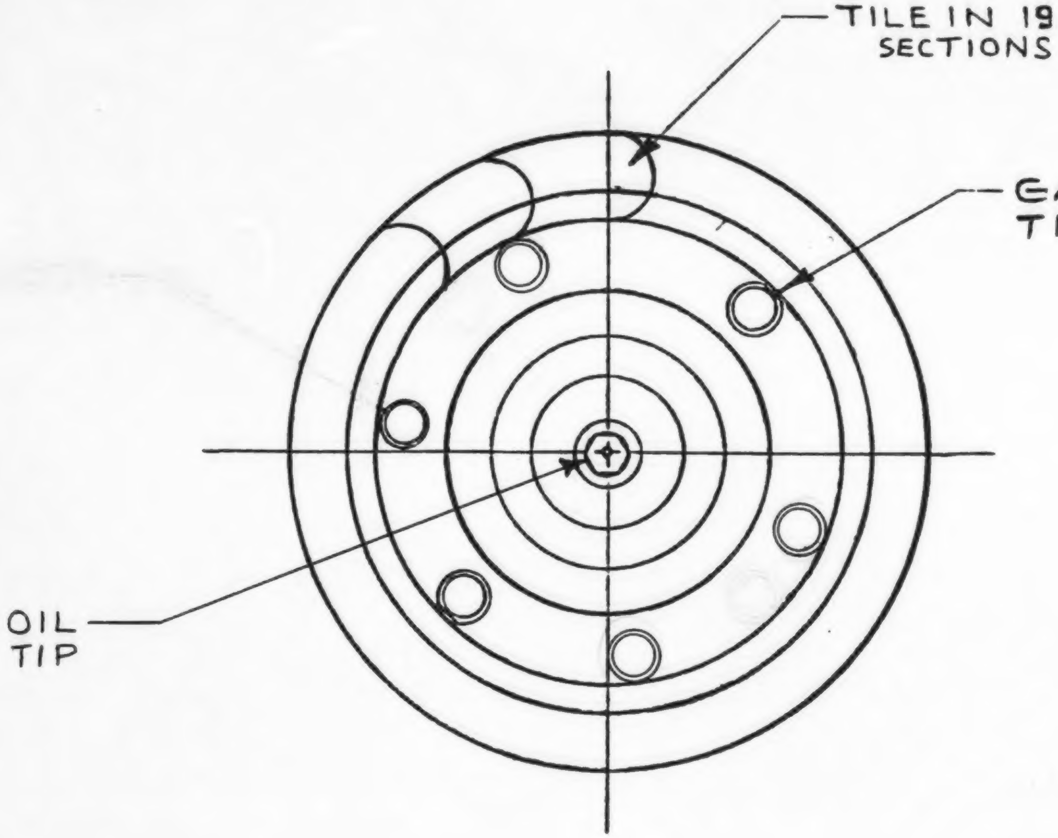
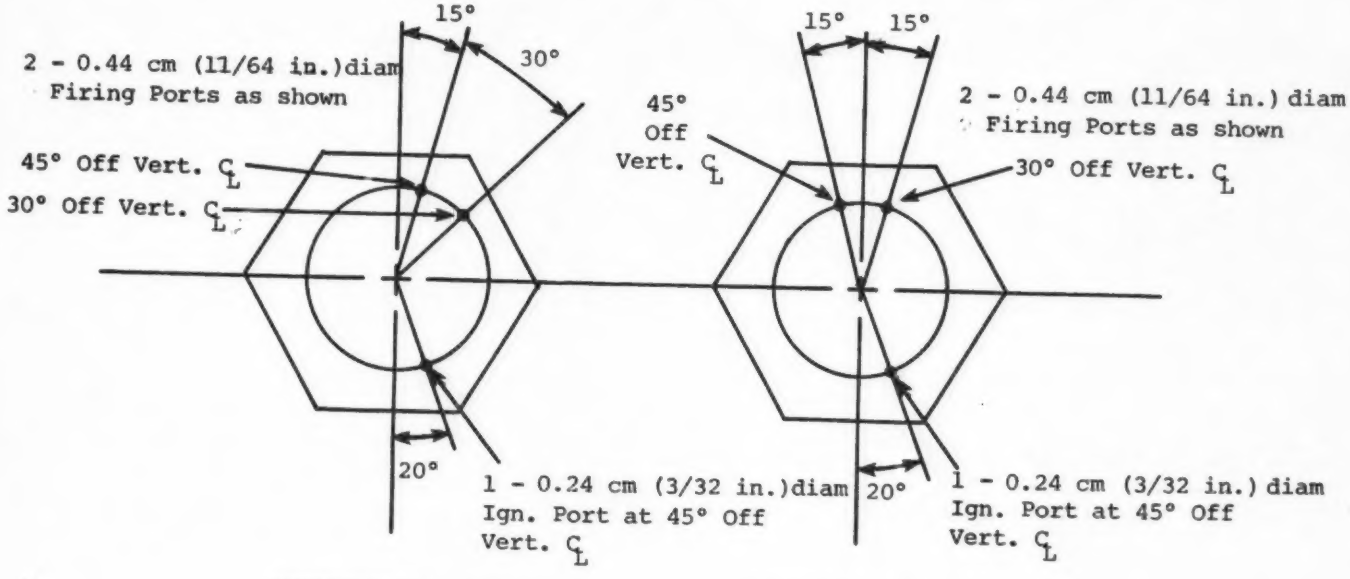

TILE IN 19 SECTIONS
GAS TIP
OIL TIP

Figure 4-26. Plan view of tertiary air burner.


15°
30°
2 - 0.44 cm (11/64 in.)diam
Firing Ports as shown
45° Off Vert. ℄
30° Off Vert. ℄
20°
1 - 0.24 cm (3/32 in.)diam
Ign. Port at 45° Off
Vert. ℄
15°
15°
45°
Off
Vert. ℄
2 - 0.44 cm (11/64 in.) diam
Firing Ports as shown
30° Off Vert. ℄
20°
1 - 0.24 cm (3/32 in.) diam
Ign. Port at 45° Off
Vert. ℄

CONFIGURATION IIB

CONFIGURATION IIC

Figure 4-27. Gas tip hole drilling patterns for the tertiary air burner.

Figure 4-28 shows the effect of stack O_2 changes on NO_x emissions for the tertiary air burner. With the Configuration IIB gas tips, the O_2 was varied from 4.0% down to 0.4%. CO concentration at the low O_2 point was 83 ppm (corrected to 3% O_2, dry). NO_x concentration at that point was 122 ppm, a reduction of 20% from the baseline value, but still higher than the baseline NO_x emission from the conventional MA-16 burner.

A second gas tip hole pattern (Configuration IIC) was installed in an attempt to lower NO_x emission. This configuration had more radially-oriented injection orifices and produced a much longer, narrower flame.

Baseline NO_x measurements were about 100 ppm (corrected to 3% O_2, dry). Stack O_2 was varied from 4.1% down to 2.1%. CO concentration at the minimum O_2 was 47 ppm (corrected to 3% O_2, dry). NO_x at that O_2 setting was 76 ppm (corrected to 3% O_2, dry), a reduction of 24% from the baseline concentration. The results of these tests are also shown in Figure 4-28.

Firing rate changes were also made with the Configuration IIB gas tips. Figure 4-29 shows NO_x emissions as a function of firing rate for the tertiary air burner. At 100% of capacity (6.5×10^6 Btu/hr) NO_x emission was 155 ppm (corrected to 3% O_2, dry) and dropped to 109 ppm (corrected to 3% O_2, dry) at 37% of capacity.

A series of air register adjustments were made at approximately 3% O_2 with the tertiary air burner but produced no appreciable reduction in NO_x levels. This is illustrated in Figure 4-30. Stack oxygen was varied at register condition 3. As Figure 4-28 shows, the NO_x levels were about the same as those obtained when all registers were 100% open.

The effect of furnace temperature on NO_x emissions with natural gas fuel and with the pattern IIC tips is shown in Figure 4-31. The NO_x level tends to rise until a stack temperature of about 1200 K (1700 °F) is attained. Since many tests were conducted with stack temperatures less than 1200 K due to the length of time required for furnace heat-up (about 4 hours) some temperature-related effects were unavoidable in the data. However, the effects were fairly small and were also minimized where possible by conducting a related series of tests (e.g., different stack O_2 points) over the shortest time possible and making baseline checks periodically during the day.

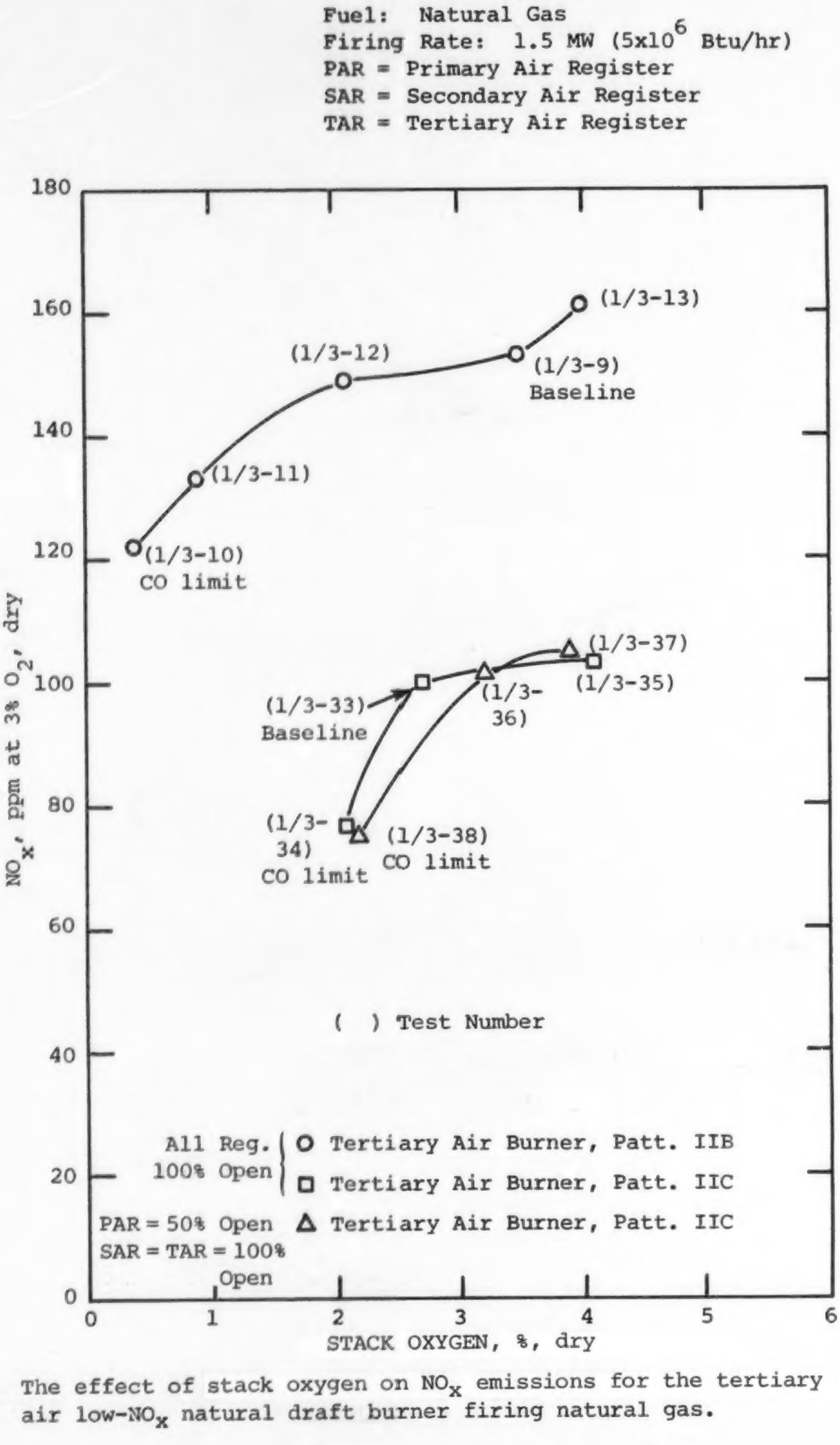


Figure 4-28. The effect of stack oxygen on NO_x emissions for the tertiary air low-NO_x natural draft burner firing natural gas.

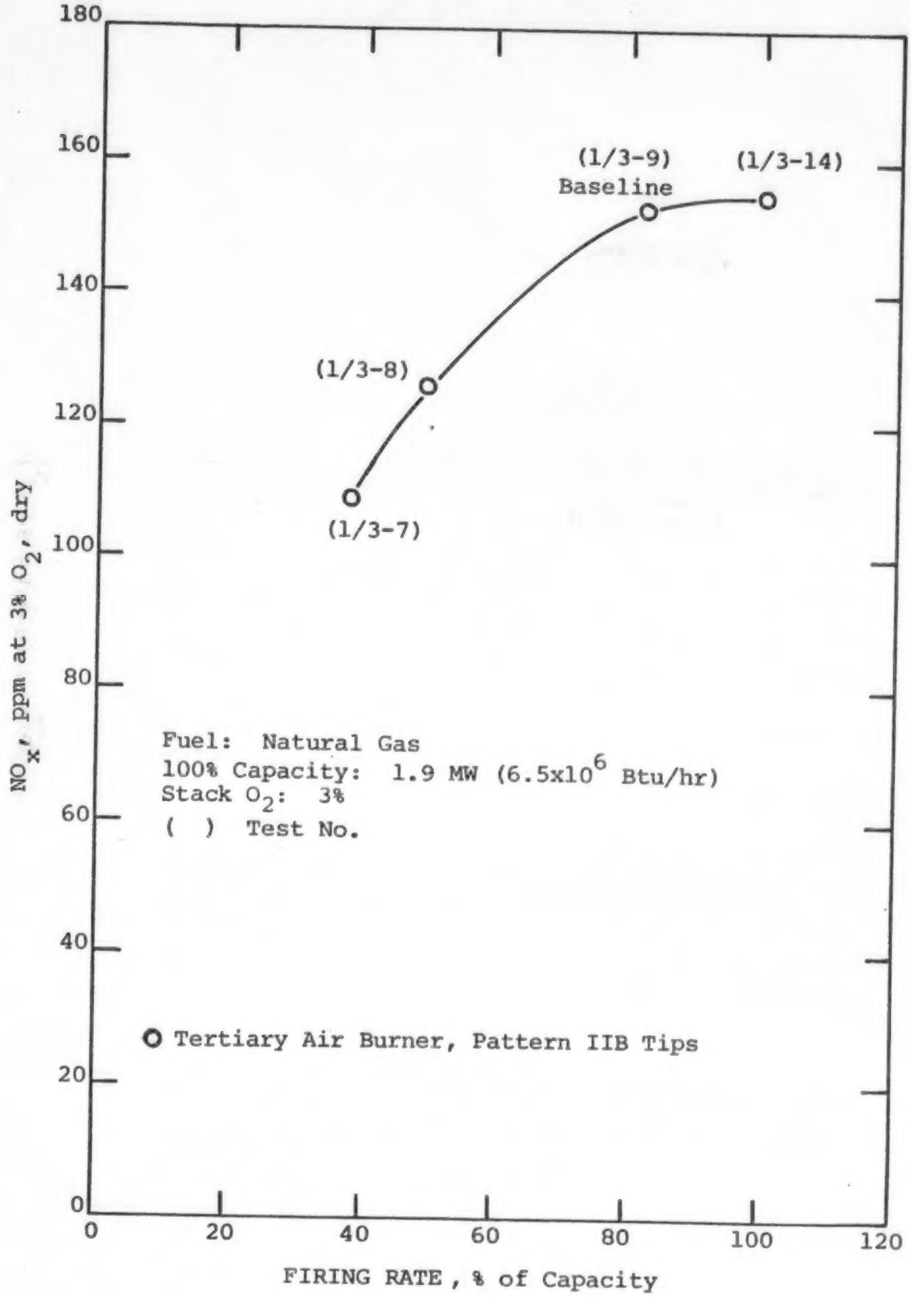
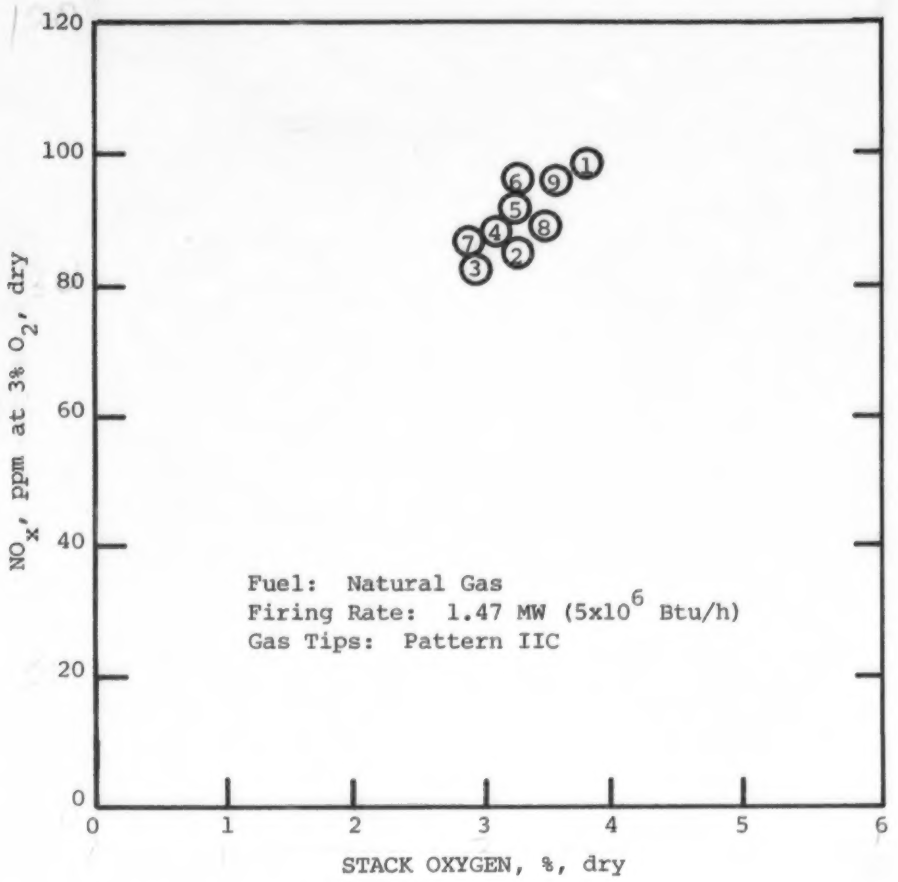


Figure 4-29. The effect of firing rate changes on NO_x emissions for the low-NO_x tertiary air natural draft burner firing natural gas.



AIR REGISTER SETTINGS:

① All Registers 100% Open (1/3-24b)

② PAR = Closed (1/3-25) SAR = TAR = 100% Open

③ PAR = 50% Open (1/3-26) SAR = TAR = 100% Open

④ SAR = Closed (1/3-27) PAR = TAR = 100% Open

⑤ SAR = 50% Open (1/3-28) PAR = TAR = 100% Open

⑥ PAR = SAR = 50% Open TAR = 100% Open (1/3-29)

⑦ PAR = Closed, SAR = 50% Open, TAR = 100% Open (1/3-30)

⑧ PAR = Closed, Tar = 50% Open, SAR = 100% Open (1/3-31)

⑨ PAR = SAR = TAR = 50% Open (1/3-32)

PAR = Primary Air Register
SAR = Secondary Air Register
TAR = Tertiary Air Register

Figure 4-30. The effects of air register adjustments and stack oxygen on NO$_x$ emissions for the tertiary air burner firing natural gas.

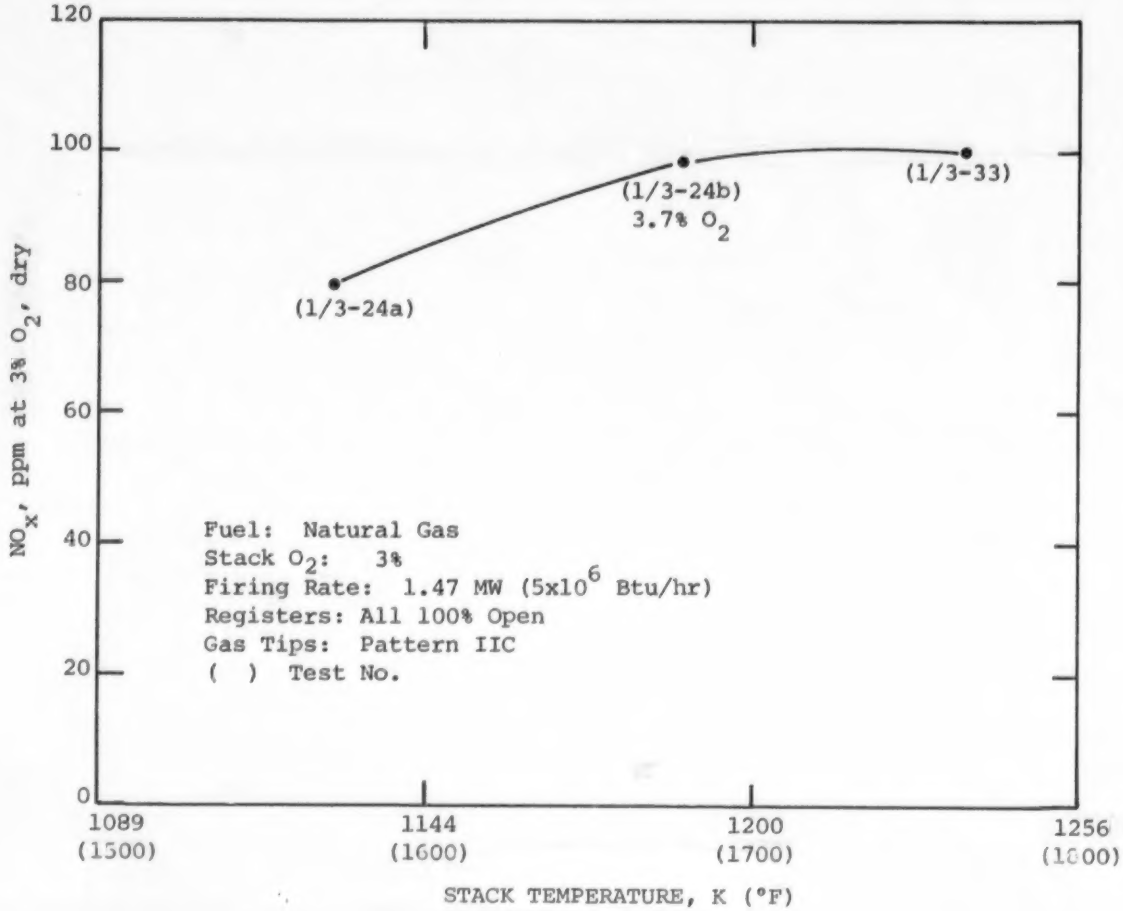


Figure 4-31. The effect of furnace temperature on NO$_x$ emissions for the tertiary air burner firing natural gas.

The data indicate that there was no large temperature effect on NO_x emissions with No. 6 oil.

Tests on No. 6 oil with the tertiary air burner consisted of O_2 variation at the normal air register settings, air register adjustments, and O_2 changes at the register setting which gave the lowest NO_x emissions. An oil tip with a 40-deg. spray angle was used for all of the tests with No. 6 oil.

The effect of stack O_2 on NO_x emissions for the tertiary air burner using No. 6 oil is shown in Figure 4-32. The curve is fairly flat, showing baseline NO_x emissions to be 272 ppm (corrected to 3% O_2, dry) and dropping to 235 ppm (corrected to 3% O_2, dry) at 0.5% O_2, for a reduction of 14%. The CO level at 0.5% O_2 was 57 ppm (corrected to 3% O_2, dry). These baseline NO_x values were ∿ 15% less than the baseline NO_x emissions from the MA-16 burner with a 40-deg. spray angle tip.

The effect of air register adjustments is shown in Figure 4-33. The setting which produced the lowest NO_x had the primary air register 10% open and the secondary and tertiary air registers 100% open. As with natural gas fuel, decreasing the primary air seemed to produce the largest effect from the standpoint of NO_x emissions. At 2.9% O_2, NO_x emission at this register setting was 200 ppm (corrected to 3% O_2, dry), a reduction of 26% from tertiary air burner baseline or 37.5% from the MA-16 burner baseline.

The variation of stack O_2 at this register setting could not be completed because of a severe coking problem which was encountered in the burner. It was discovered that the oil tip had been placed about 1/4 inch too low in the burner throat. In addition, because of the small primary air register opening, less primary air was available for oxidation of the fuel. These two conditions resulted in the "dropout" of a large amount of unburned fuel and forced an early stoppage of the tests. Thus, the reduction in NO_x emissions achieved with the primary air register 10% open might not be practically attained in actual application.

A few tests on the tertiary air burner were also conducted using a shale oil of high nitrogen content (2.1% by weight). Stack O_2 changes coupled with relatively minor register adjustments were made. NO emissions

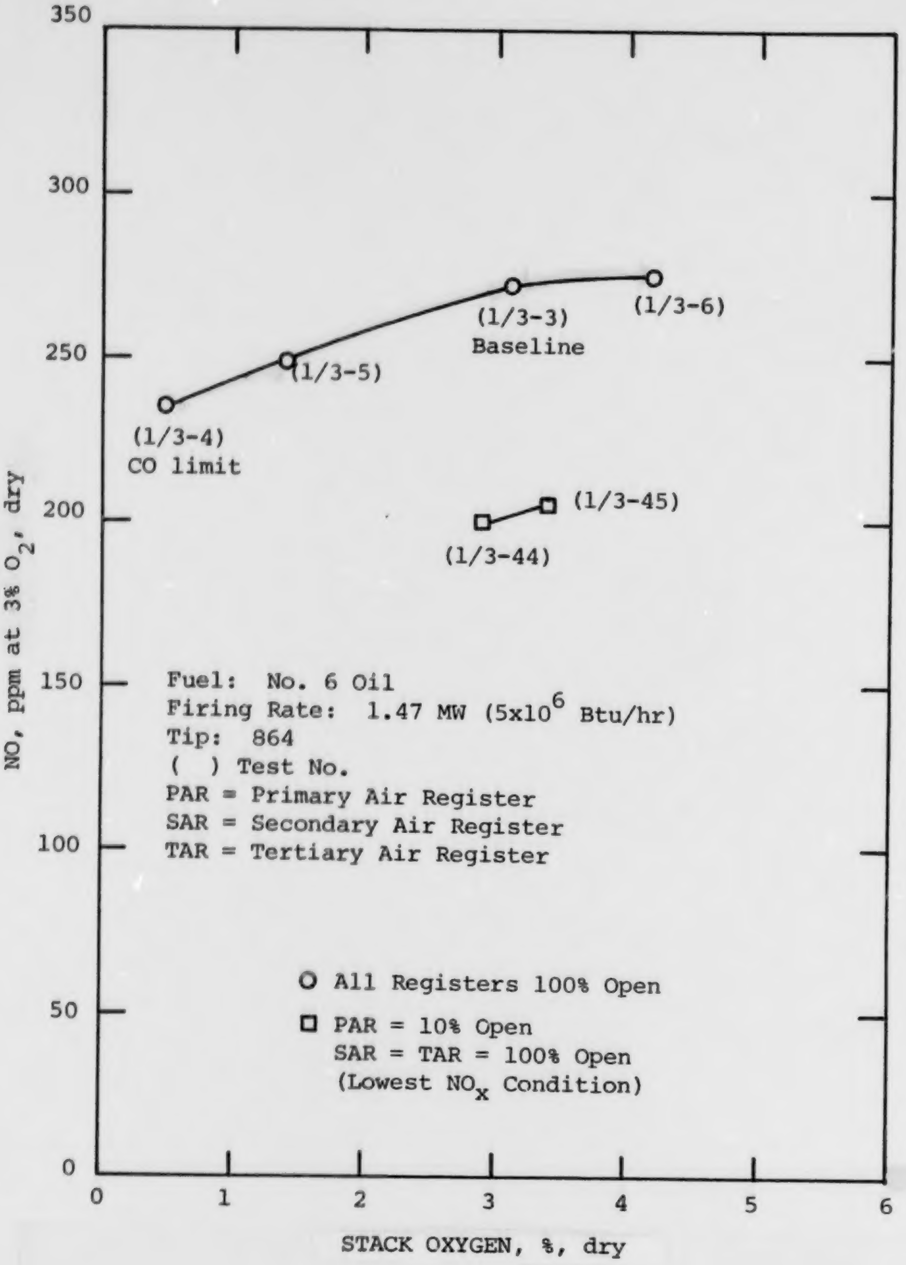


Figure 4-32. The effect of stack oxygen at two register settings on NO_x emissions for the tertiary air burner firing No. 6 oil.

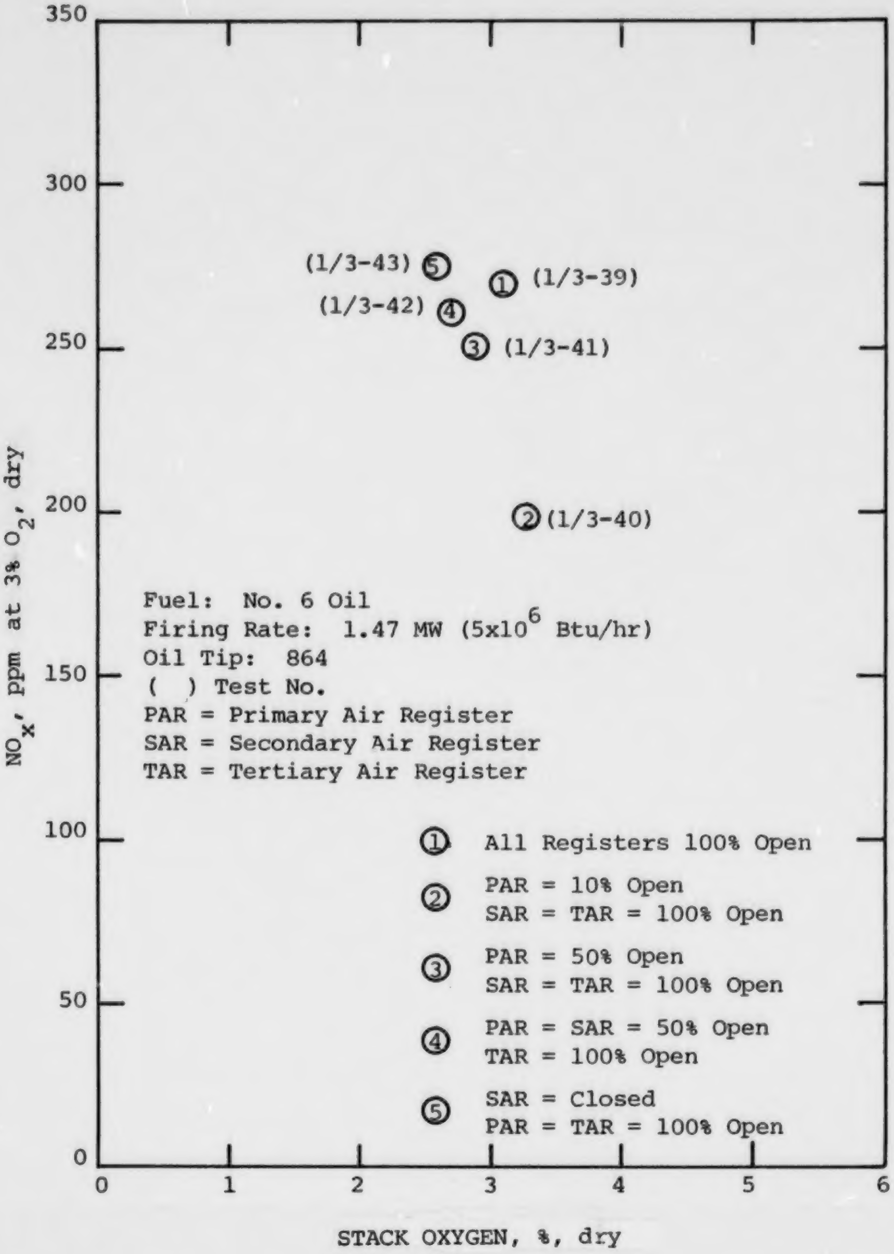


Figure 4-33. The effects of air register adjustments on NO_x emissions for the tertiary air burner firing No. 6 oil.

varied from 526 ppm (corrected to 3% O_2, dry) at 6.5% O_2 to 200 ppm (corrected to 3% O_2, dry) at 0.35% O_2. The CO concentration at the latter O_2 was > 2000 ppm. At an optimum-low O_2 of 1.2%, NO emission was 295 ppm (corrected to 3% O_2, dry), or 33% less than the emission at 3.2% O_2 (439 ppm, corrected to 3% O_2, dry). Also, at this point all registers were closed somewhat, increasing the draft and lengthening the flame.

For one test, major register adjustments were made: the primary air register was very nearly closed, the secondary air register was 25% open, and the tertiary air register was 100% open. In that case, at 3.0% O_2, the NO concentration was 329 ppm (corrected to 3% O_2, dry), or approximately 25% less than the 439 ppm measured at 3.2% O_2 with all registers 50% open. Figure 4-34 summarizes the shale oil test data.

Samples of the shale oil and No. 6 oil were taken, and the analyses are shown in Table 4-1.

4.3.5 Low-NO_x Burner (Recirculating Tile)

A low-NO_x burner incorporating a self-recirculating tile was evaluated in the research furnace. A special tile was used to achieve some recirculation of fuel vapors and the products of combustion in the immediate vicinity of the burner. The recirculation of these gases is intended to lower the flame zone temperature and, thus, lower thermal NO_x. The tile was located on the furnace floor just above the fuel injection plane.

Instead of a throat (used in the conventional burner) the burner had a 25-cm-diameter (10-in.) diffuser cone attached to the oil gun to create a low pressure zone near the fuel injection plane.

Figures 4-35a and 4-35b are a plan view of the burner showing the positioning of the diffuser cone and oil and gas tips, and a schematic of the recirculating tile, respectively.

Figure 4-36 shows the gas tip configurations used in the tests with natural gas. Configuration III was used initially but resulted in high NO_x levels at baseline conditions (129 ppm corrected to 3% O_2, dry). In an attempt to lower the NO_x by increasing the amount of recirculation, the gas tips were lowered 1.3 cm (1/2 in.). The NO_x level increased, however, probably because of the increased recirculation of high temperature combustion products without sufficient entrainment of cooler gases.

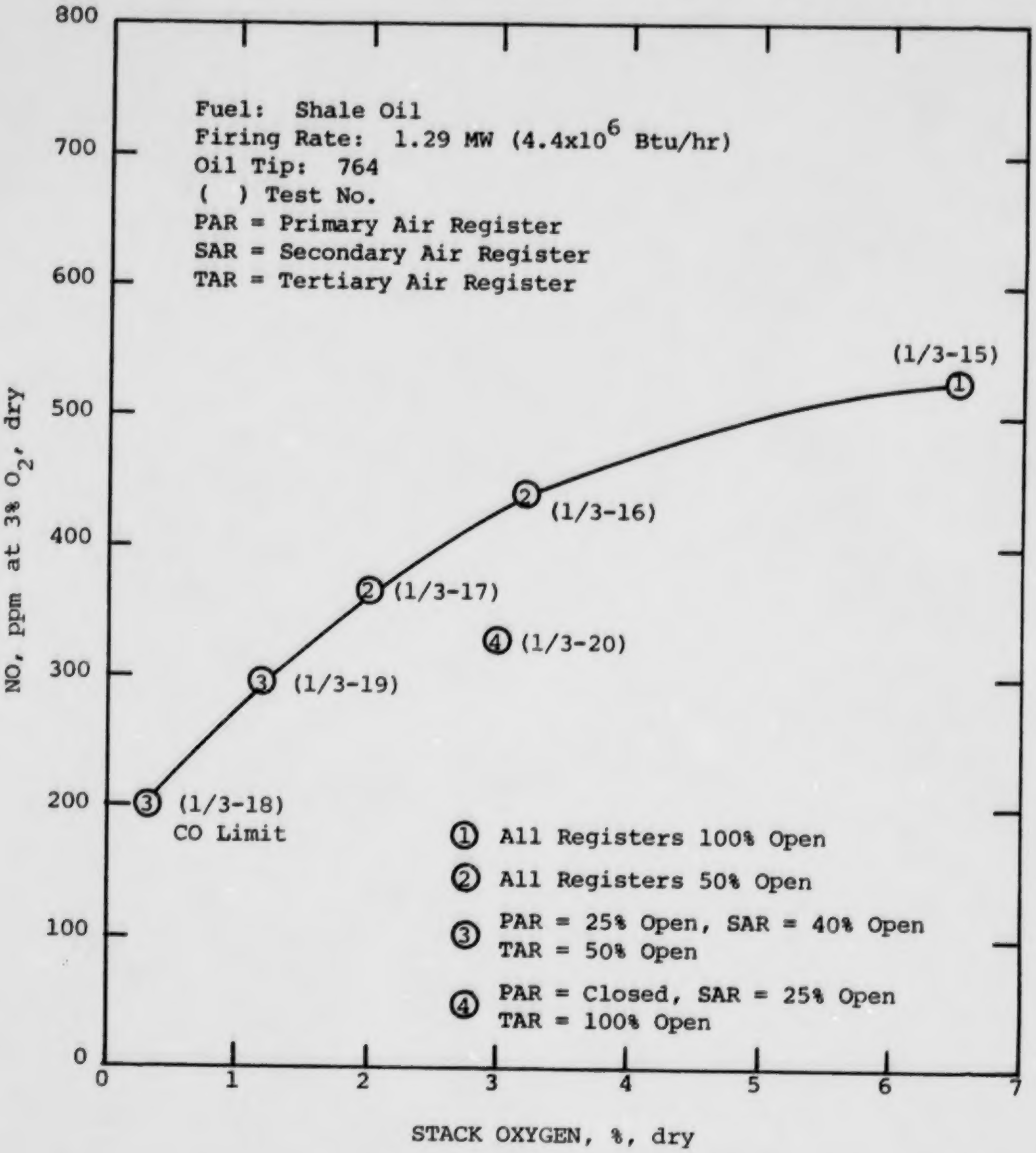


Figure 4-34. The effects of stack oxygen and register adjustments on NO emissions for the tertiary air burner firing shale oil.

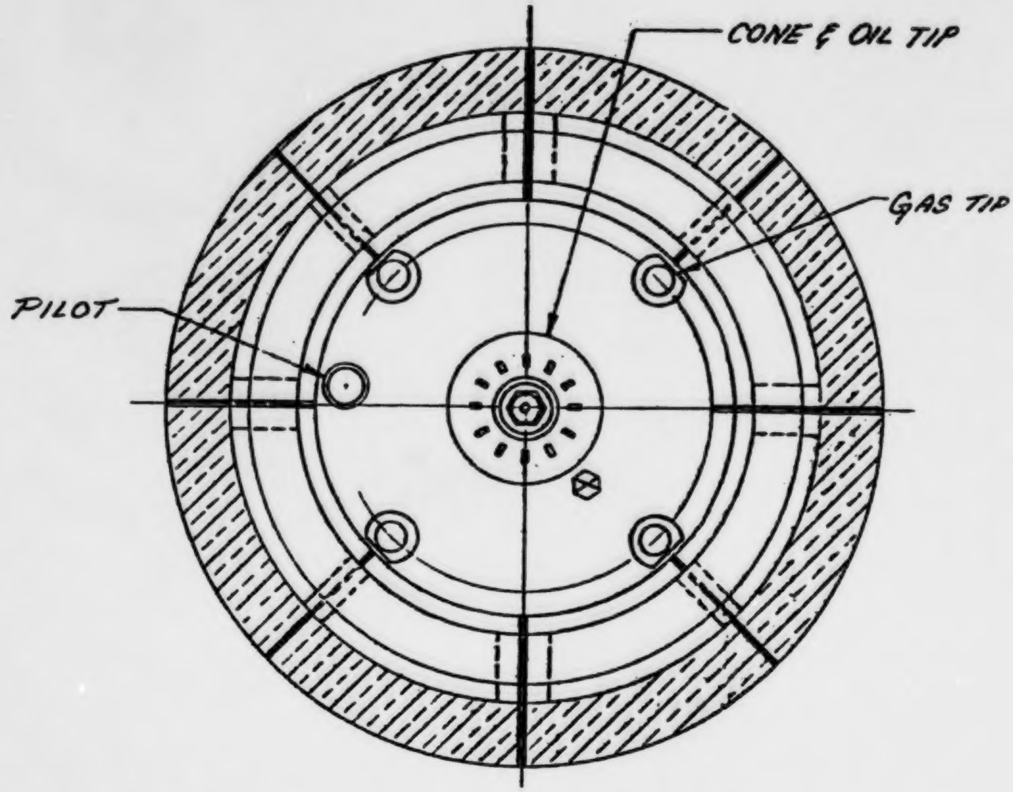

CONE & OIL TIP
GAS TIP
PILOT

Figure 4-35a. Plan view of recirculating tile burner for natural draft process heater.

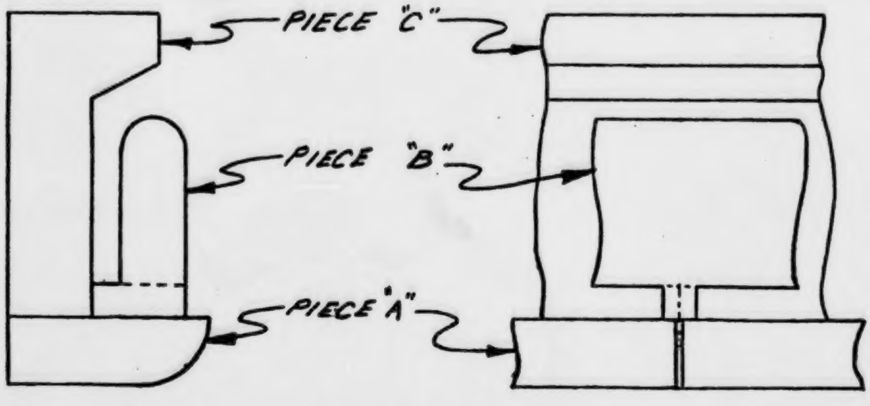
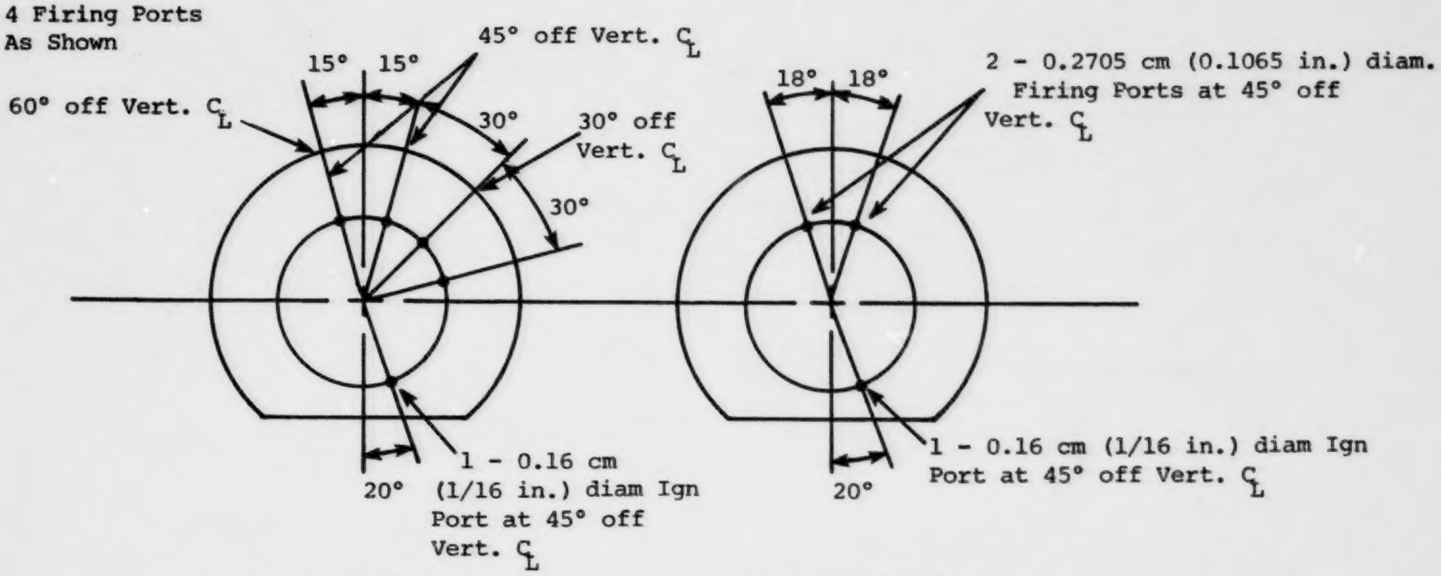

PIECE "C"
PIECE "B"
PIECE "A"

Figure 4-35b. Schematic of recirculating tile showing cross-section (left) and elevation (right).


4 Firing Ports
As Shown
60° off Vert. ℄
15°
15°
45° off Vert. ℄
30°
30° off Vert. ℄
30°
20°
1 - 0.16 cm (1/16 in.) diam Ign Port at 45° off Vert. ℄
18°
18°
2 - 0.2705 cm (0.1065 in.) diam. Firing Ports at 45° off Vert. ℄
20°
1 - 0.16 cm (1/16 in.) diam Ign Port at 45° off Vert. ℄

CONFIGURATION III

CONFIGURATION I

Figure 4-36. Gas tip hole drilling patterns for recirculating tile burner.

A tip pattern having injection orifices producing less swirl (Configuration I) was tried next. The intent was to decrease mixing and lengthen the flame. The NO_x level decreased to a baseline value of 104 ppm (corrected to 3% O_2, dry) with these gas tips, still only slightly lower than the baseline NO_x value of 114 ppm (corrected to 3% O_2, dry) found on the conventional MA-16 burner.

Using the Configuration I tips, the stack O_2 was varied from 4.4% down to the limit at which CO appeared, 0.6%. At 0.6% O_2, NO_x emission decreased by 20% to 83 ppm (corrected to 3% O_2, dry). The CO concentration at this condition was 44 ppm (corrected to 3% O_2, dry). The effects of stack oxygen as well as the change in gas tips on NO_x emissions is shown in Figure 4-37.

The effect of firing rate changes on NO_x emissions for natural gas fuel is shown in Figure 4-38. NO_x emission levels remained constant (115 ppm, corrected to 3% O_2, dry) at firing rates from 50% to 100% of capacity (100% capacity = 6.5×10^6 Btu/hr) and dropped somewhat (to 110 ppm, corrected to 3% O_2, dry) at 28% of capacity. Stack O_2 was necessarily high, however, at this low capacity to provide flame stability. One explanation for the flatness of the NO vs. firing rate curve is that a greater degree of mixing offsets the lower firebox temperatures at low firing rates. The most likely explanation, however, is that the burner tile temperature is probably relatively constant over most of the load range. Thus, as the firing rate was decreased, the air flow decreased while the residence time in the burner tile increased. These offsetting trends probably resulted in the constant NO_x levels.

Tests on the recirculating tile burner were also conducted firing No. 2 oil using an oil tip with a 60-deg. spray angle (30 deg. either side of the vertical centerline of the furnace). No. 2 oil was used rather than No. 6 oil, for which tests had originally been planned, because of coking problems which had been experienced with No. 6 oil on this particular type of burner. The wide angle oil tip was expected to result in better recirculation by having the flame impinge on the burner tile just below the top of piece C.

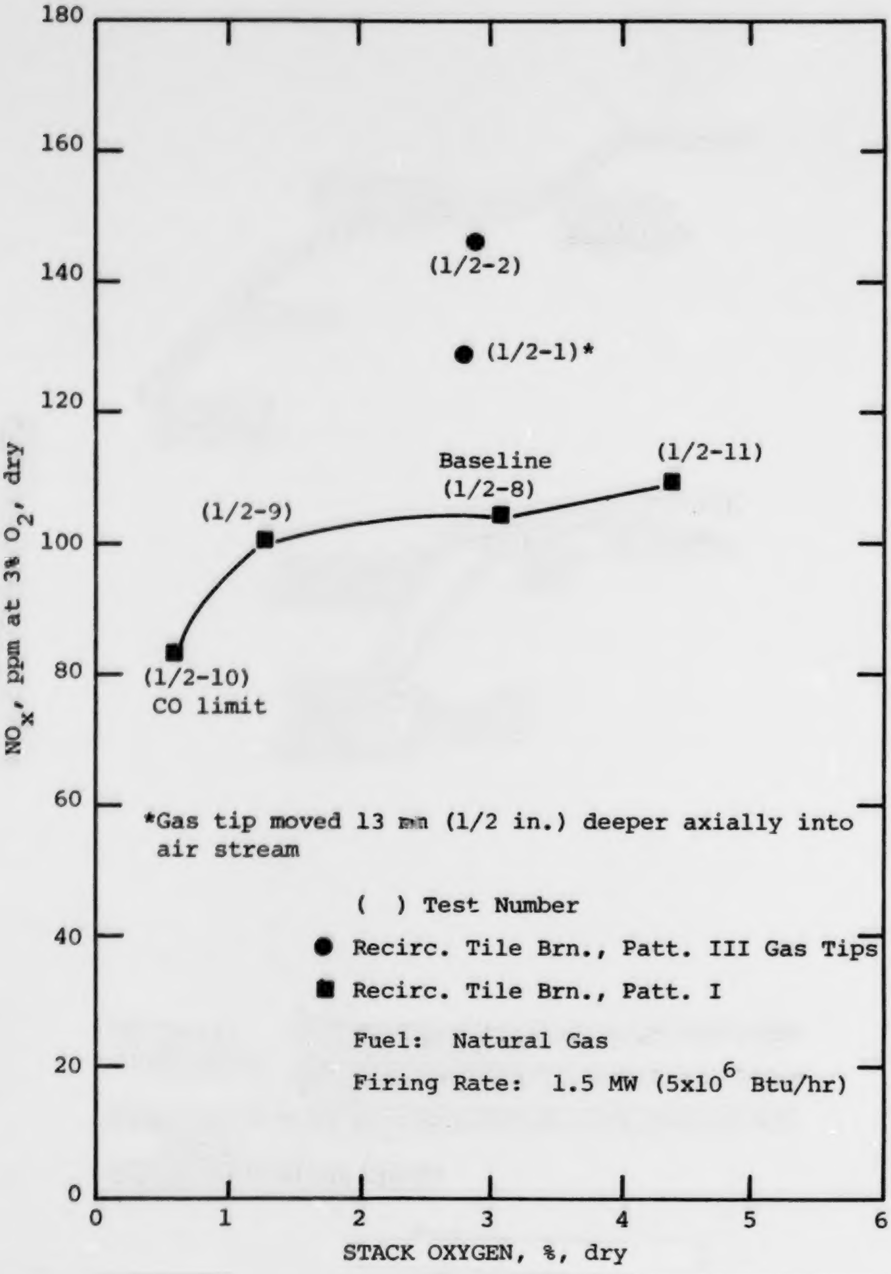


Figure 4-37. The effect of stack oxygen on NO$_x$ emissions for the recirculating tile low-NO$_x$ natural draft burner firing natural gas.

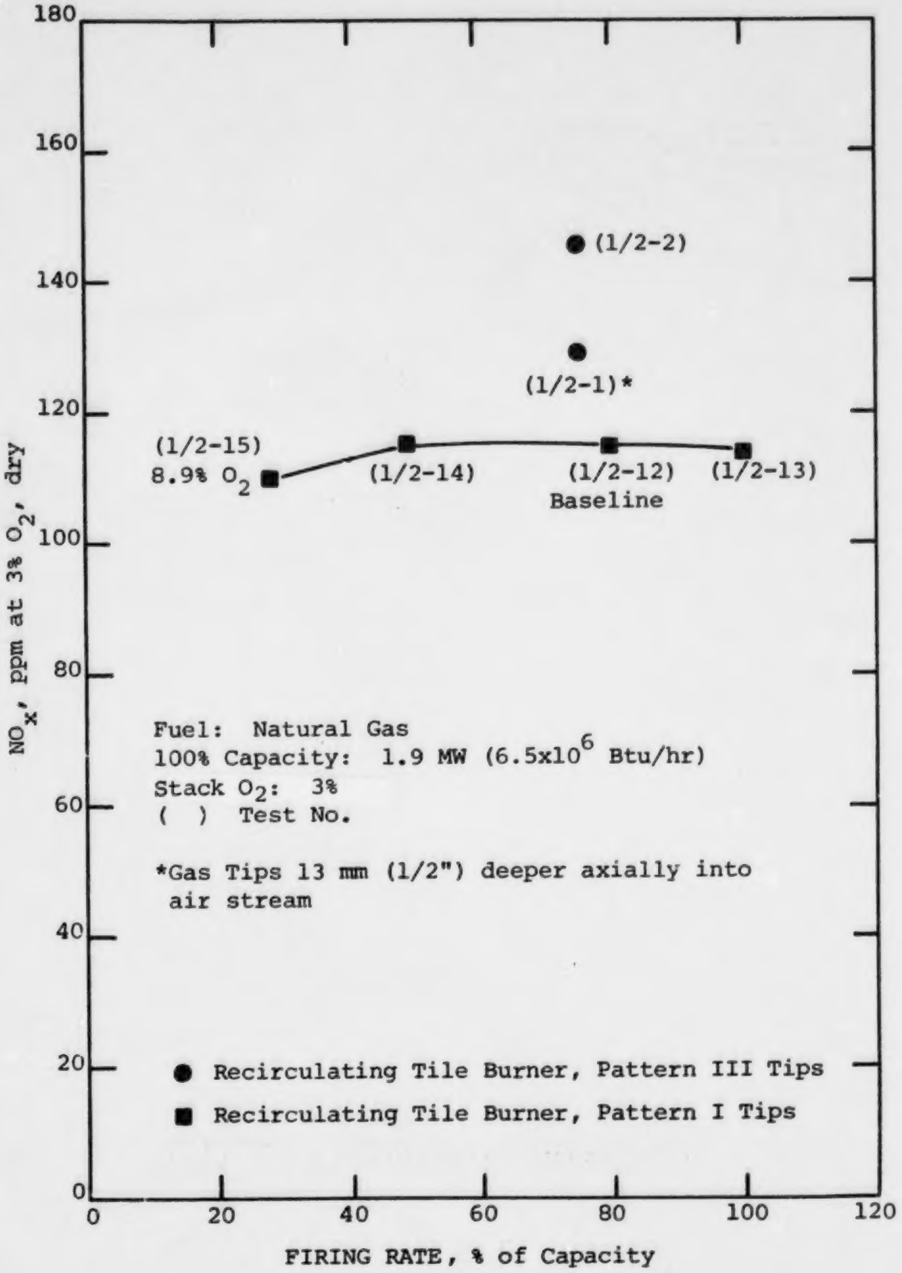


Figure 4-38. The effect of firing rate changes on NO$_x$ emissions for recirculating tile low-NO$_x$ natural draft burner firing natural gas.

Baseline NO_x emissions (at 4% O_2) for the recirculating tile burner firing No. 2 oil were 110 ppm (corrected to 3% O_2, dry). Stack O_2 was varied from 5.1% down to 0.5% at which point the CO concentration was 147 ppm (corrected to 3% O_2, dry). The lowest NO_x emission occurred at a stack O_2 of 1.4% and was 98 ppm (corrected to 3% O_2, dry), down 11% from the baseline value. Further reduction of the O_2 appeared to have no significant result on NO_x emissions. Figure 4-39 summarizes the effect of stack O_2 on NO_x emissions.

Figure 4-39 also shows a significant drop in NO_x emissions at 50% capacity for stack O_2 of 5.7%. The NO_x concentration at this condition was 85 ppm (corrected to 3% O_2, dry), or 23% less than baseline. Time constraints prevented testing at other firing rates.

4.3.6 Flue Gas Recirculation

Flue gas recirculation has been demonstrated to be an effective method of NO_x reduction for industrial boilers. Thus far, flue gas recirculation has not been applied to process heaters for NO_x reduction. The objective of this test series was to evaluate the effect of flue gas recirculation on gaseous emissions and thermal efficiency in a process heater. It was not possible to duct actual flue gases from the stack to the burner because a high temperature fan was not available. In order to simulate FGR, a system was installed as shown schematically in Figure 4-40. An auxiliary burner was installed which exhausted into a combustion air duct leading to the burner plenum. A gas-gas heat exchanger was installed to control the temperature of the combustion air-flue gas mixture. The percentage of recirculated flue gas was varied by adjusting the firing rate for the auxiliary burner. Flue gas recirculation rates were varied up to a maximum of 40% approximately when firing natural gas and No. 6 oil.

The effect of FGR rate is shown in Figure 4-41 where NO_x is plotted as a function of percent FGR for natural gas firing. The flue gas recirculation is defined by the following expression:

$$\%\ \text{FGR} = \frac{\text{Recirc. mass flow rate} \times 100}{\text{Combustion air flow + Recirc. mass flow + Fuel flow}}$$

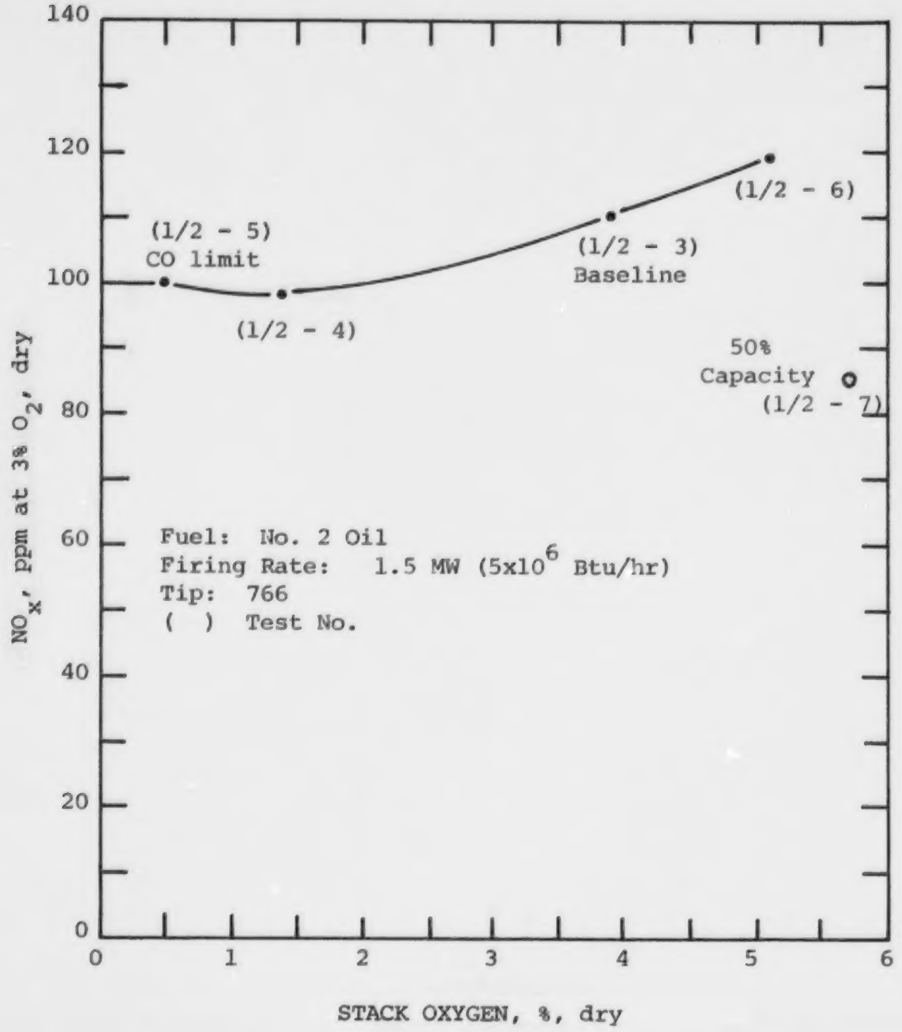


Figure 4-39. The effect of stack oxygen on NO$_x$ emissions for the recirculating tile burner firing No. 2 oil.

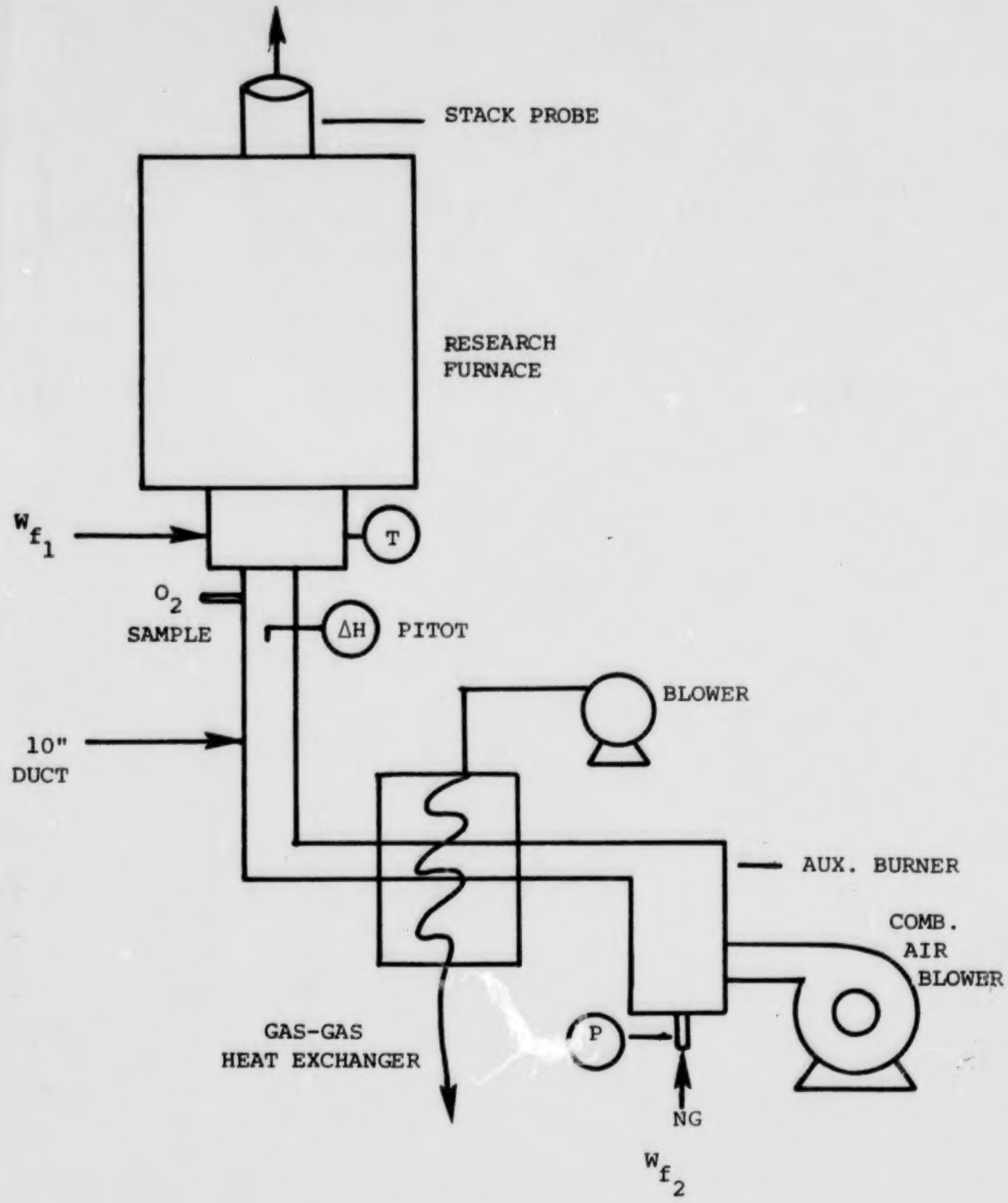

STACK PROBE
RESEARCH FURNACE
W_{f_1}
T
O_2 SAMPLE
ΔH PITOT
BLOWER
10" DUCT
AUX. BURNER
COMB. AIR BLOWER
P
GAS-GAS HEAT EXCHANGER
NG
W_{f_2}

Figure 4-40. Schematic of FGR setup at Location 1.

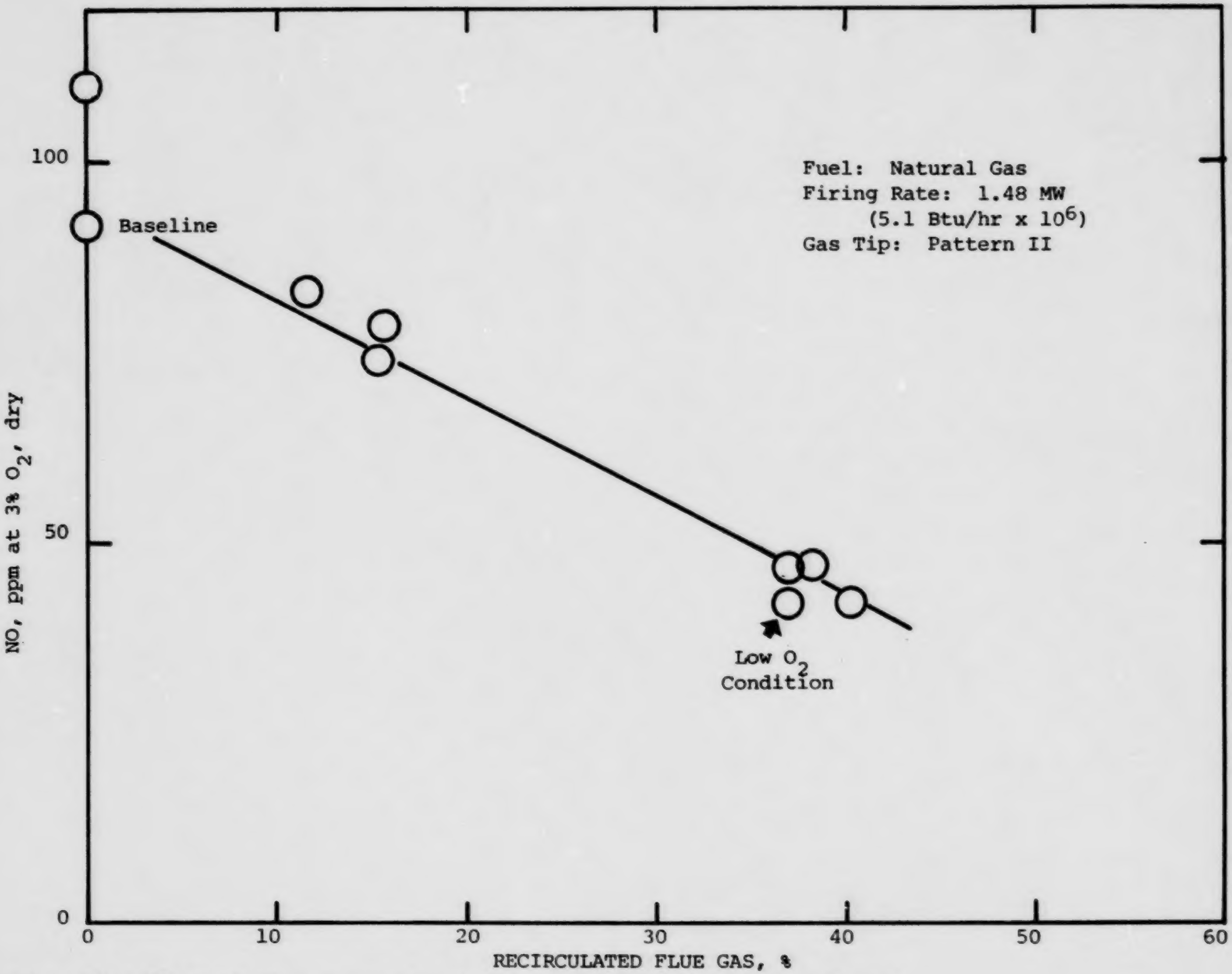


Figure 4-41. The effect of flue gas recirculation on NO emissions (natural gas).

A reduction in NO_x of 57% from the baseline condition was achieved with FGR at the normal O_2 level. The overall O_2 level was reduced until the CO limit was reached. The CO limit was the point at which CO emissions increased sharpely as the O_2 was decreased. This limiting value of stack O_2 was 0.7% O_2. CO concentration was 31ppm dry at 3% O_2. A reduction in NO_x of 62% was measured with the combination of FGR and low O_2 operation.

Figure 4-42 presents NO_x as a function of FGR rate for No. 6 oil firing. FGR alone resulted in a reduction of 34% at the maximum recirculation rate. The combination of FGR and low O_2 operation yielded a reduction of 40% in NO_x emissions.

4.3.7 Steam Injection

The effect of steam injection on NO and NO_x emissions was evaluated for natural gas firing with an MA-16 burner. Two methods of steam injection were tried. In the first method, steam was injected into the gas manifold and the steam/gas mixture then injected radially inward through the normal gas tips. The steam flow rate was varied up to a maximum of 0.0098 kg/sec (78 lb/hr). The effect of steam injection flow rate on NO emissions is shown in Figure 4-43. The maximum reduction in NO occurred with the maximum steam flow rate. NO emissions were reduced 32% from the baseline condition at 0.0098 kg/sec (78 lb/hr) flow rate.

An alternate method of steam injection was evaluated to determine the influence on NO_x emissions. In this method the steam was injected through the oil gun of a DBA-16 burner at the burner centerline. Since steam for fuel oil atomization is already supplied to the oil gun, injection through the oil gun is a simpler modification than steam injection through the gas tips. Further, it was hoped that by experimenting with the positioning of the oil tip relative to the gas tips, NO_x emissions could be reduced below the levels of the previous tests.

Figure 4-44 shows the effect of steam injection through the oil gun on NO_x emissions for the DBA-16 burner with Configuration II tips, normal orientation. Maximum reduction in NO_x was achieved at the highest rate of steam injection--114 ppm at 0.0095 kg/s (75 lb/h) steam flow. Very little difference in NO_x production was observed at the other steam flow rate used (0.0067 kg/s or 53 lb/h). Thus, the lowest NO_x emissions for steam injection through the oil gun were 16% less than the normal baseline (3% O_2) NO_x levels for the DBA-16 burner.

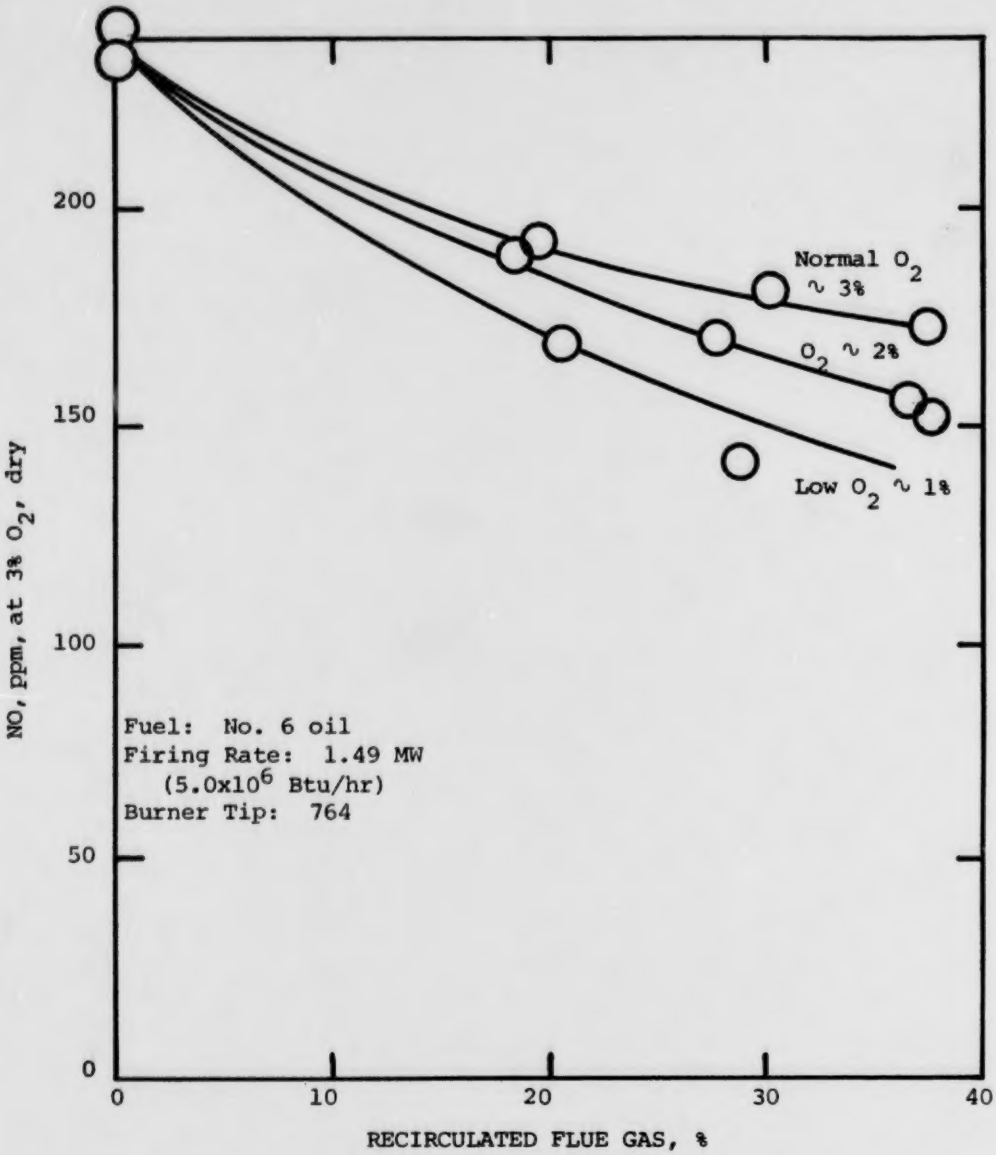


Figure 4-42. The effect of flue gas recirculation on NO emissions (No. 6 oil).

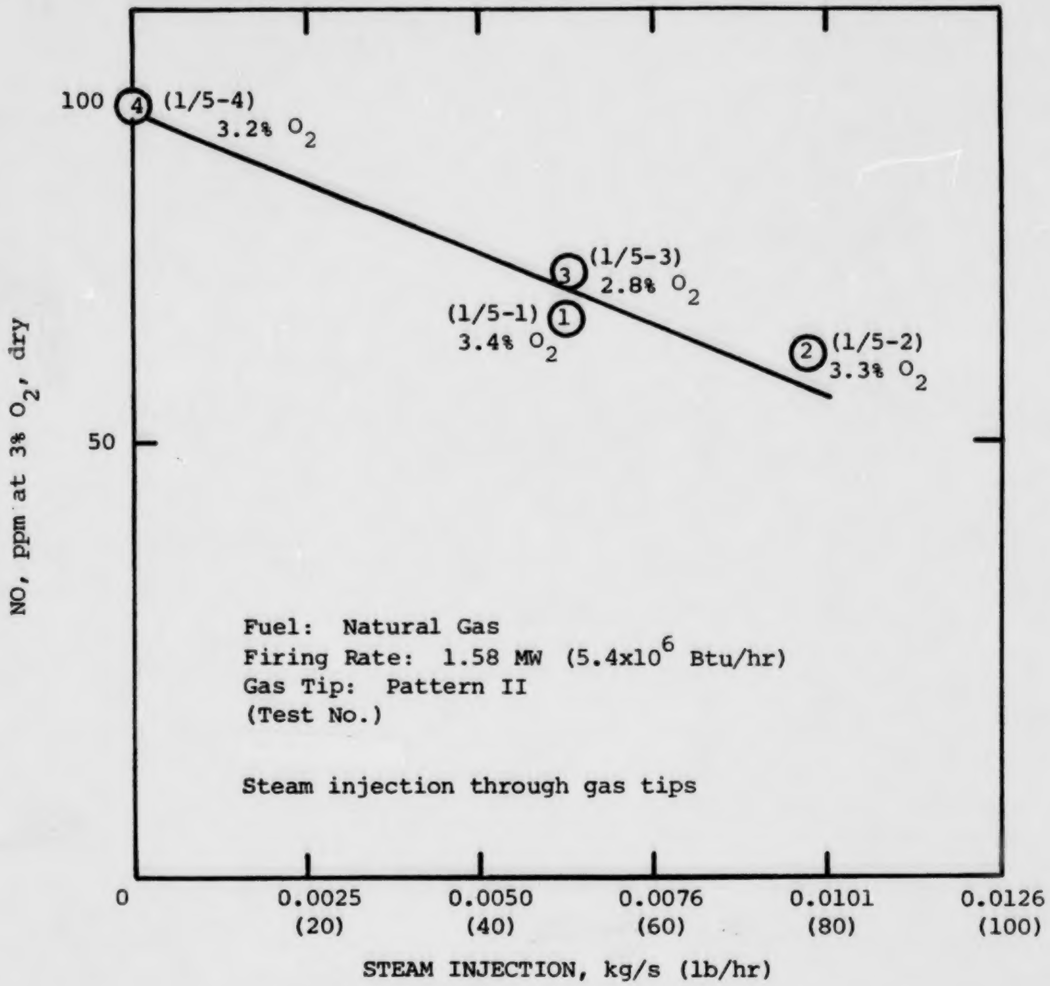


Figure 4-43. The effect of steam injection on NO emissions for the MA-16 burner firing natural gas.

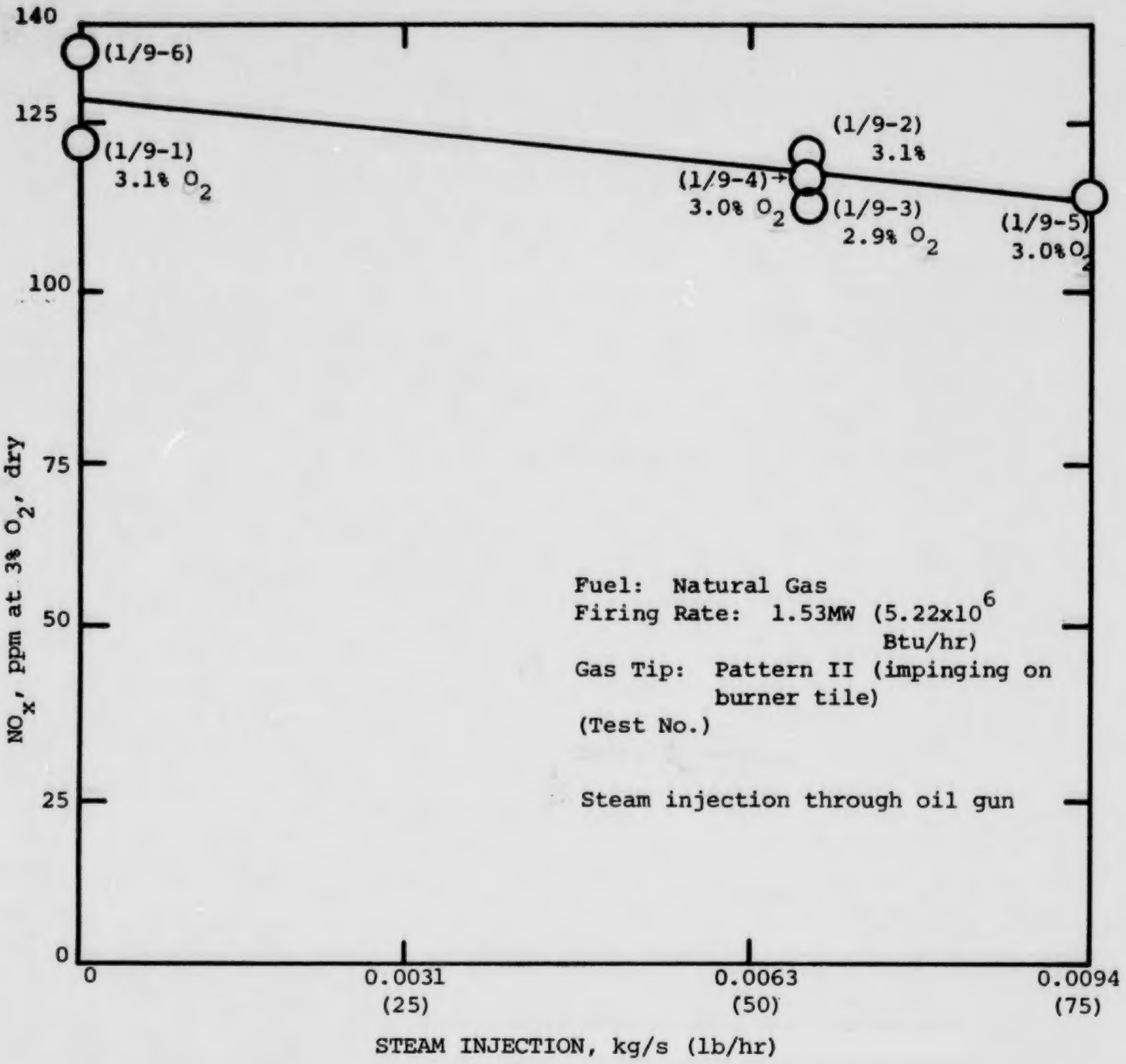


Figure 4-44. The effect of steam injection on NO_x emissions for the DBA-16 burner firing natural gas.

The influence of steam injection on NO_x emissions was not nearly as strong for steam injection through the oil gun as it was for steam injection through the gas tips as is seen by comparing the slopes of the curves in Figures 4-43 and 4-44. The difference in baseline NO_x emissions between the MA-16 and the DBA-16 burners was roughly 25 ppm as indicated by Figures 4-43 and 4-44. This result was observed again during excess air variation tests and is discussed below.

4.3.8 Altered Fuel Injection Geometry

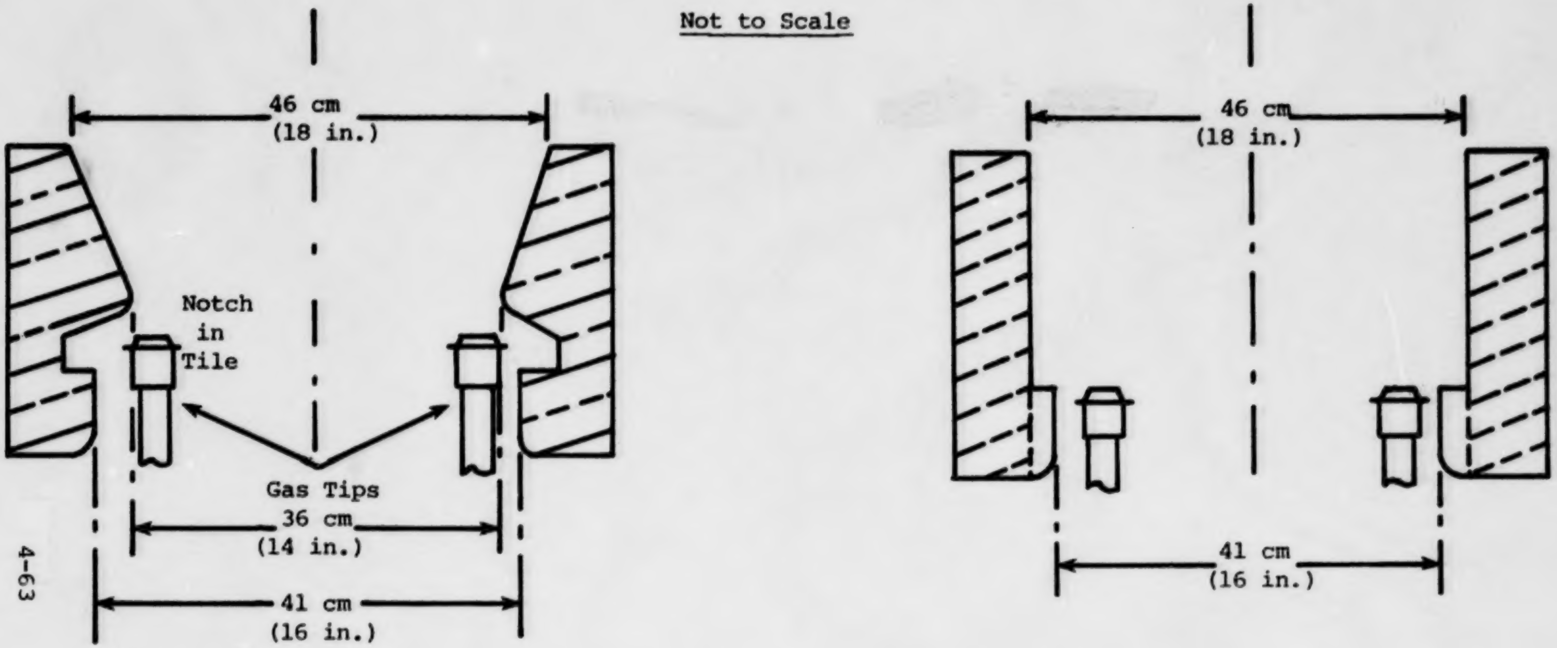
Previous work with boilers has shown that NO_x emissions can be reduced by altering fuel injection geometry to produce locally fuel-rich zones in the flame. The fuel-rich zones are at a lower temperature and result in lower overall NO_x production. Based on the results of cold flow tests in KVB's laboratory, the fuel injection geometry was modified for a DBA-16 natural draft burner.

A DBA burner was selected because the straight-sided tile more closely resembled the cold flow conditions than did the MA-16 tile. Figure 4-45 presents a schematic comparison of the two types of burner tiles.

Tests revealed that NO_x emissions at baseline conditions (with no modifications) for the DBA-16 burner were higher than the emissions from the MA-16 burner tested (see Fig. 4-46), contrary to expectations. Apparently, the straight-sided tile of the DBA-16 confines high-temperature combustion gases to a smaller volume, resulting in more intense burning and, consequently, higher NO_x emissions.

In the first test series, standard Configuration II gas tips were installed in the DBA-16 with the center firing port facing radially outward, perpendicular to the burner circumference. On the basis of the cold flow test results reported by KVB, this tip orientation was expected to delay mixing of fuel and air, thus producing a longer, less intense flame, and lower NOx emissions.

The tests showed that NO_x emissions were indeed lower for this tip configuration than for the standard configuration (compare Figs. 4-46 and 4-47). At 3% O_2, the NO_x concentration with outward-facing firing ports was approximately 94 ppm (dry, corrected to 3% O_2), about 33% lower than the NO_x emissions from the standard tip orientation. At an O_2 of 1.1%, the NO_x level was 78 ppm, a 32% reduction from the standard orientation NO_x level. The


Not to Scale
46 cm
(18 in.)
Notch
in
Tile
Gas Tips
36 cm
(14 in.)
41 cm
(16 in.)
46 cm
(18 in.)
41 cm
(16 in.)

Standard Tile for MA-16 Burner

Standard Tile for DBA-16 Burner

Figure 4-45. Comparison of the tiles used in the conventional natural draft process heater burners tested at Location 1.

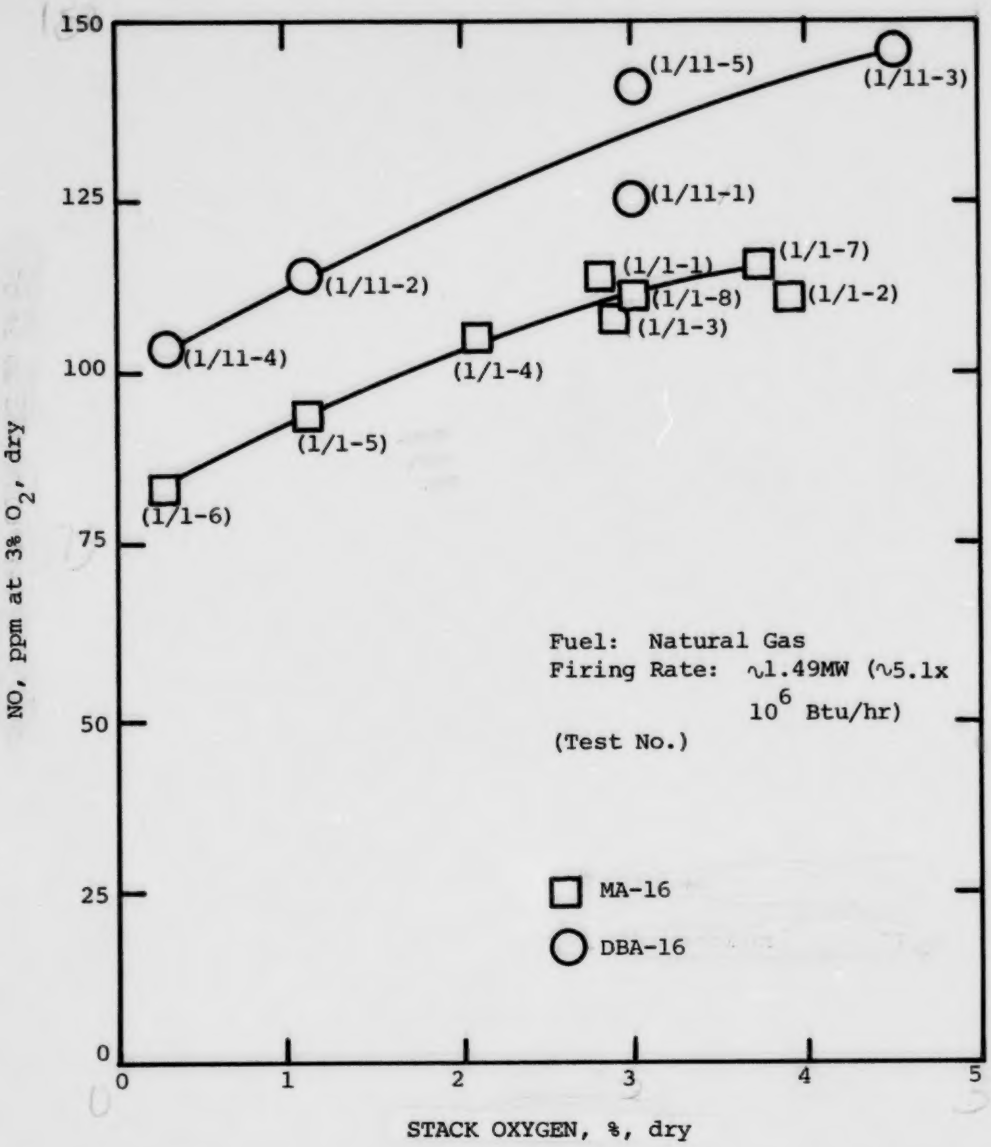


Figure 4-46. NO emissions as a function of stack O_2 for natural draft burners firing natural gas, normal tip configuration.

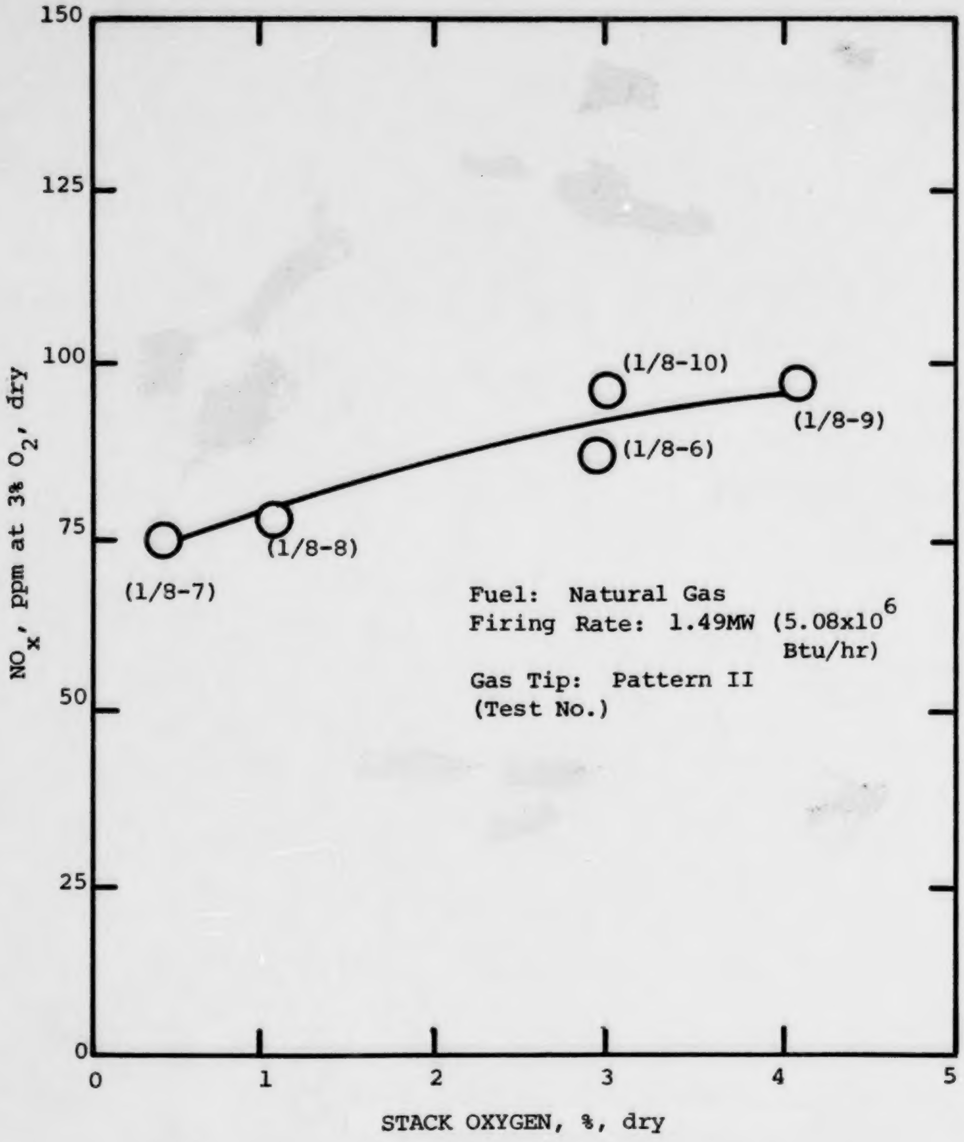


Figure 4-47. NO_x emission as a function of stack O_2 for DBA-16 burner firing natural gas with gas tips radially outward.

CO limit (615 ppm CO) occurred at 0.5% O_2, compared with 0.3% O_2 for the standard configuration with a CO concentration of 678 ppm. NO_x at this point was down to 73 ppm, 29% below the standard configuration value at the CO limit.

The flame shape with the reverse tip orientation was shorter than the normal flame and segmented into four fuel-rich regions, one above each of the gas tips. The flame appeared to be quite lazy at low firing rates.

4.4 SUMMARY OF HOT-FIRING TEST RESULTS

In Figures 4-48 and 4-49, the NO_x emissions from the conventional MA-16 and DBA-16 burners and the tertiary air burner for various test conditions are graphed as a function of stack oxygen, firing natural gas and No. 6 oil. The unmodified burners (all registers 100% open in the case of the tertiary air burner) are represented by heavy symbols and curves, and modifications to each burner are represented by light symbols and curves.

It is important to note that the percent reductions in NO_x shown in Table 4-3 for the lowest O_2 conditions may not be attainable in an actual process heater since they were obtained at or very near the CO limit. Operation with such low excess air may not be possible in a natural draft process heater because it is likely to result in positive stack static pressures which would violate plant safety codes. In addition, the lack of fine control of the fire at low drafts increases the chances for operation with high levels of combustibles. Thus, these figures probably represent an ideal upper bound for NO_x reduction potential for the various combustion modification techniques considered.

Table 4-3 shows that the largest percent reductions in NO_x occurred with staged air or flue gas recirculation techniques. With SCA, these reductions seem to be a relatively strong function of excess air whereas with FGR they are a rather weak function of excess air. With natural gas fuel, all modifications (except the tertiary air burner) appeared to increase furnace efficiency. With No. 6 oil, efficiency decreased slightly with SCA and decreased with FGR, but increased when FGR was coupled with low excess air.

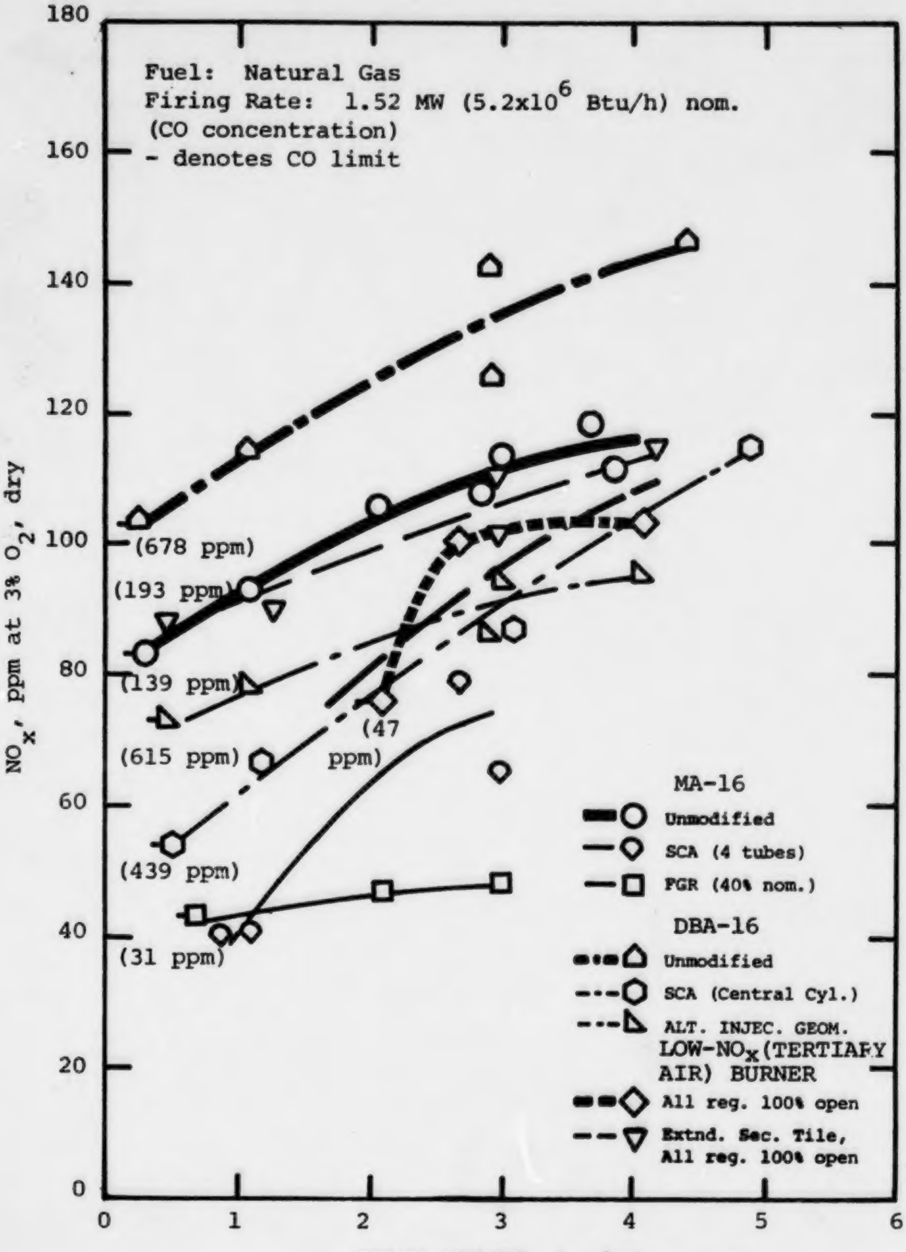


Figure 4-48. Summary of NO_x emissions as a function of stack oxygen for subscale natural draft furnace firing natural gas.

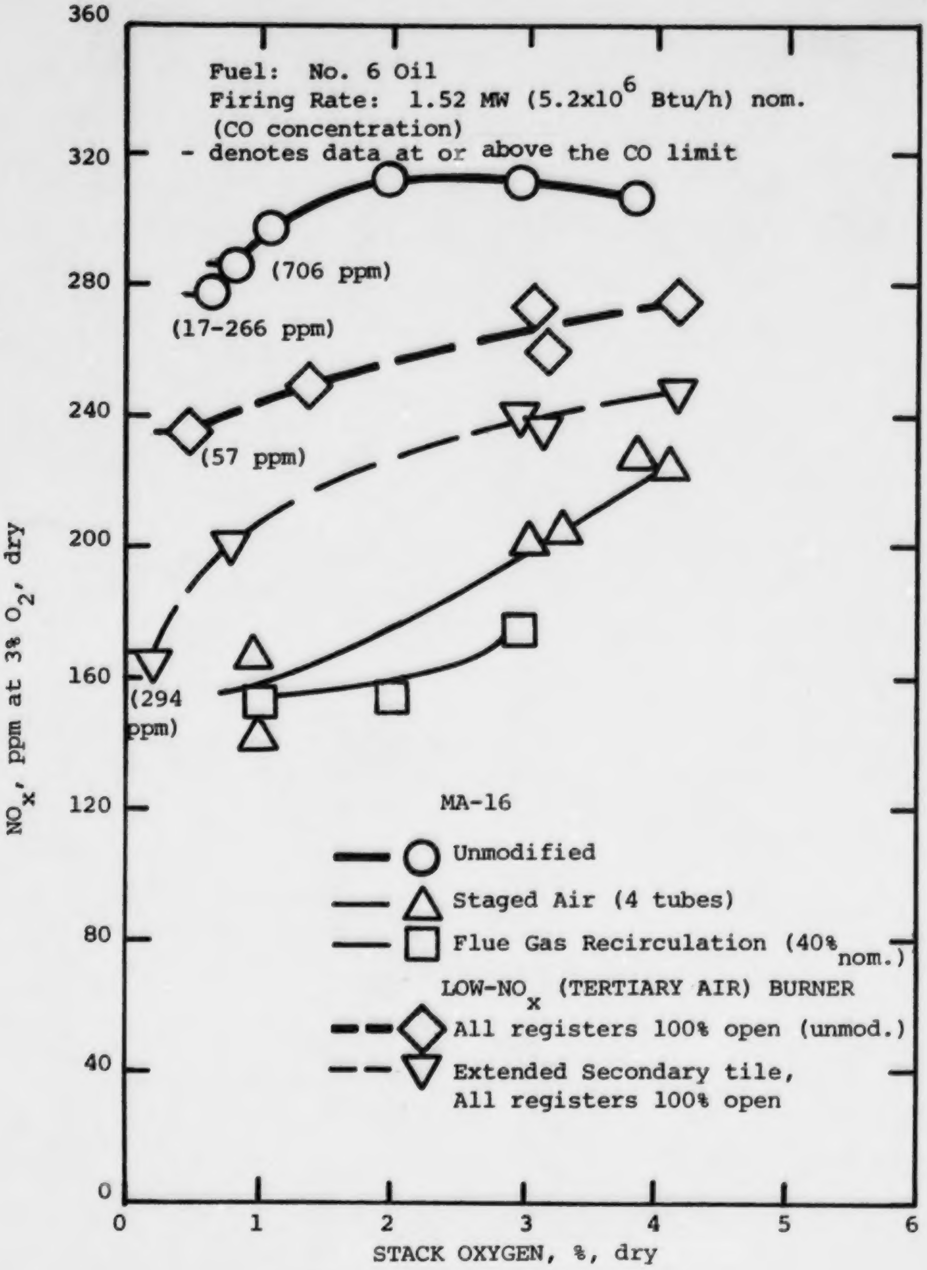


Figure 4-49. Summary of NO$_x$ emissions as a function of stack oxygen for subscale natural draft furnace firing No. 6 oil.

TABLE 4-3. SUMMARY OF NO_x REDUCTION AND EFFICIENCY CHANGE AS A FUNCTION OF COMBUSTION MODIFICATION TECHNIQUE FOR NATURAL GAS AND NO. 6 OIL FOR NATURAL DRAFT BURNERS

Fuel	Natural Gas		No. 6 Oil	
Average Baseline NO_x	ppm,dry @ 3% O_2	ng/J	ppm,dry @ 3% O_2	ng/J
MA-16	107	54.6	285	160
DBA-16	131	66.8	--	--
Combustion Modification Technique	NO_x Reduction (%)	Efficiency Change (%)	NO_x Reduction (%)	Efficiency Change (%)
Lowered Excess Air	27	+ 4.7	10	+ 0.1
Staged Combustion Air				
Floor Lances, Normal O_2	46	+ 0.7	35	- 0.7
Floor Lances, Low O_2	67	+ 2.6	51	- 0.4
Central Cylinder, Normal O_2*	31	0.0	--	--
Central Cylinder, Low O_2*	59	+ 3.4	--	--
Tertiary Air Burner, Lowest NO_x Configuration (relative to average baseline NO_x for the MA-16)	30	- 2.0	42	0.0
Flue Gas Recirculation				
Normal O_2	59	+ 4.7	31	- 2.6
Low O_2	63	+ 4.9	39	+ 2.0
Steam Injection, Normal O_2	33	--	--	--
Altered Fuel Injection Geometry				
Normal O_2*	31	0.0	--	--
Low O_2*	44	+ 3.4	--	--

* NO_x reduction is relative to average baseline NO_x for the DBA-16.

In cases where baseline data could not be taken on the same day during which modifications were tested, the average NO_x concentration for the modification is compared to the average NO_x from the unmodified burner at baseline conditions. The average unmodified burner baseline NO_x concentrations are given in Table 4-3. NO_x emission reduction for the tertiary air burner was reported relative to the average unmodified baseline emissions from the MA-16 burner. The efficiency changes reported in Table 4-3 result from a comparison of the efficiencies occurring at modified conditions with efficiencies measured at baseline conditions at similar stack temperatures using a conventional MA-16 burner.

The percent reductions in NO_x observed for modifications to the DBA-16 burner are expected to occur for the same modifications to the MA-16 burner with the possible exception of altered injection geometry (where the difference in burner tiles may play an important role in the mixing patterns resulting from the modified injection scheme).

4.5 COST EFFECTIVENESS OF COMBUSTION MODIFICATIONS TO NATURAL DRAFT PROCESS HEATERS

4.5.1 Summary

The cost effectiveness of the combustion modifications applicable to natural draft process heaters has been evaluated, and the results are summarized in Table 4-4. All costs are based on 1978 dollars.

The initial installed cost for each of the modifications is shown in Table 4-5 for three different heater sizes. The largest and smallest sizes--147 MW ($500x10^6$ Btu/h) and 2.9 MW ($10x10^6$ Btu/h), respectively--represent the two extremes in firing rate for refinery process heaters. The intermediate size of 73.3 MW ($250x10^6$ Btu/h) was chosen for this cost analysis because it is the current size limit above which steam boilers are regulated by federal emission standards.

The total annualized cost per Mg of NO_x reduction shown in Table 4-4 was determined by amortizing the initial fixed capital costs given in Table 4-5 at 20% (corresponding to straight-line depreciation of the capital equipment over 12 years, and assuming a 10% cost of capital, state and federal taxes totalling approximately 11%, and insurance charges of 0.5%). The annual

TABLE 4-4. COST EFFECTIVENESS (\$/Mg of NO_x Reduction) OF COMBUSTION MODIFICATIONS TO A NATURAL DRAFT PROCESS HEATER (NOT INCLUDING ANNUAL FUEL COSTS/SAVINGS)

Modification	Heater Size					
	2.9 MW ($10x10^6$ Btu/h)		73.3 MW ($250x10^6$ Btu/h)		147 MW ($500x10^6$ Btu/h)	
	Natural Gas	No. 6 Oil	Natural Gas	No. 6 Oil	Natural Gas	No. 6 Oil
Low Excess Air	0	0	0	0	0	0
Altered Injection Geom. (Normal O_2)	\$6.60	--	\$0.78	--	\$0.78	--
Altered Injection Geom. (with LEA)	\$4.70	--	\$0.55	--	\$0.55	--
Staged Air - Central Cyl. (Normal O_2)	\$200	--	\$43	--	\$33	--
Staged Air - Central Cyl. (with LEA)	\$100	--	\$23	--	\$18	--
Staged Air - Floor Lances (Normal O_2)	\$1000	\$460	\$160	\$70	\$130	\$57
Staged Air - Floor Lances (with LEA)	\$710	\$320	\$110	\$48	\$87	\$39
Flue Gas Recirculation (Normal O_2)	\$1800	\$1200	\$320	\$200	\$320	\$200
Flue Gas Recirculation (with LEA)	\$1700	\$940	\$300	\$160	\$300	\$160
Steam Injection (no initial cost)	\$990	--	\$970	--	\$960	--
Steam Injection (incl. initial cost)	\$1400	--	\$1100	--	\$1000	--
Tertiary Air Burner	\$250	\$60	\$250	\$60	\$250	\$60

TABLE 4-5. INITIAL INSTALLED COSTS OF COMBUSTION MODIFICATIONS TO A NATURAL DRAFT PROCESS HEATER (in $)

Modification	Heater Size 2.9 MW ($10x10^6$ Btu/h)	73.3 MW ($250x10^6$ Btu/h)	147 MW ($500x10^6$ Btu/h)
Low Excess Air	0	0	0
Alternate Injection Geom.	50	150	300
Staged Air (central cyl.)	1500	8300	12800
Staged Air (floor lances)	9500	36500	59000
Flue Gas Recirculation	18500	54000	94000
Steam Injection*	3000	16300	27800
Tertiary Air Burner	1500	37500	75000

*If no existing capability

capital charge was added to the annual operating and maintenance cost to obtain the total annualized cost. These costs are shown in Table 4-6. (Annual operating costs did not include projected fuel savings or costs resulting from modifications for reasons explained below.) The total annualized cost was then divided by the annual reduction in NO_x emissions to obtain the cost effectiveness values in Table 4-4.

The annual reduction in NO_x emissions was calculated for each modification from the percent NO_x reduction listed in Table 4-3 using the formula

$$\text{Annual } NO_x \text{ reduction } (10^3 \text{ kg}) = \frac{\%\ NO_x \text{ reduction}}{100} \times \begin{array}{l}\text{Average baseline emissions} \\ \text{from conventional burner} \\ (\text{ng/J})\end{array}$$

$$\times \text{ heat input rate (W)} \times 31.536\text{x}10^6 \text{ sec/y} \times 0.8 \text{ (use factor)} \times \frac{10^{-15} \text{metric tons}}{\text{ng}}$$

NO_x emission reductions were determined relative to the conventional MA-16 burner for the following modifications:

1. Lowered Excess Air
2. Flue Gas Recirculation
3. Staged Combustion Air - Floor Lances
4. Steam Injection
5. Tertiary Air Burner

NO_x emission reductions were determined relative to the conventional DBA-16 burner for these modifications:

1. Altered Fuel Injection Geometry
2. Staged Combustion Air - Central Cylinder

Note that although Table 4-3 gives values for efficiency changes associated with each modification, these values are not appropriate for estimating annual fuel costs or savings. They are useful only inasmuch as they indicate expected trends in fuel consumption. This is so because the research heater tested by KVB at Location 1 had no process tubes and, therefore, the data do not reflect any inefficiencies or variabilities due to changes in heat transfer to a process stream.

TABLE 4-6. TOTAL ANNUALIZED COSTS (IN $) NOT INCLUDING FUEL COSTS (SAVINGS) OF COMBUSTION MODIFICATIONS TO A NATURAL DRAFT PROCESS HEATER (AMORTIZING INITIAL CAPITAL COSTS AT 20%)

	Heater Size		
Modification	2.9 MW (10×10^6 Btu/h)	73.3 MW (250×10^6 Btu/h)	147 MW (500×10^6 Btu/h)
Low Excess Air	0	0	0
Altered Injection Geom.	10	30	60
Staged Air - Central Cyl.	300	1660	2560
Staged Air - Floor Lances	1900	7330	11800
Flue Gas Recirculation	4300	18800	38100
Steam Injection (if initial installation necessary)	1900	35400	69900
Steam Injection (no initial installation required)	1300	32200	64300
Tertiary Air Burner	300	7500	15000

Figures 4-50, 4-51, 4-52, and 4-53 illustrate the relationships between estimated costs of NO_x removal and heater size.

These figures show that the simplest modifications are the most cost effective. The least expensive modifications, altered injection geometry and staged combustion air (central cylinder), were tested only in gas-firing application. It is possible that both techniques may be adapted to handle oil-firing applications as well. The more involved modifications, flue gas recirculation and staged combustion air (lances), are less cost effective although they produced the largest percent NO_x reductions.

Most modifications result in lower costs per metric ton of NO_x removed as heater size increases. Only the steam injection and the tertiary air burner cost-effectiveness ratios appear to be relatively independent of size. For the other modifications, both on natural gas and No. 6 oil firing, the cost effectiveness decreased as heater size increased from 2.9 MW (10×10^6 Btu/h) to 73.3 MW (250×10^6 Btu/h) according to the relation

$$\frac{\text{CE at 73.3 MW}}{\text{CE at 2.9 MW}} = \left(\frac{73.3}{2.9}\right)^a$$

where $-0.67 \leq a \leq -0.47$, $\bar{a} = -0.56$, and S (standard deviation) = 0.07. (Note that a is the slope of the line segments in Figs. 4-50 to 4-53).

Since

$$\text{CE} \propto (\text{size})^{-0.56}$$

and since

$$NO_x \text{ reduction} \propto (\text{size})^{1.0}$$

therefore,

$$\text{total annualized cost} \propto (\text{size})^{0.44} \quad .$$

For example, using the total annualized cost for a flue gas recirculation system for a 2.9 MW(10×10^6 Btu/h) heater given in Table 4-6 at \$4,300, one can calculate approximately the total annualized cost of flue gas recirculation for a 73.3 MW heater as follows:

$$\left(\frac{73.3}{2.9}\right)^{0.44} \times (4{,}300) = \$17{,}310$$

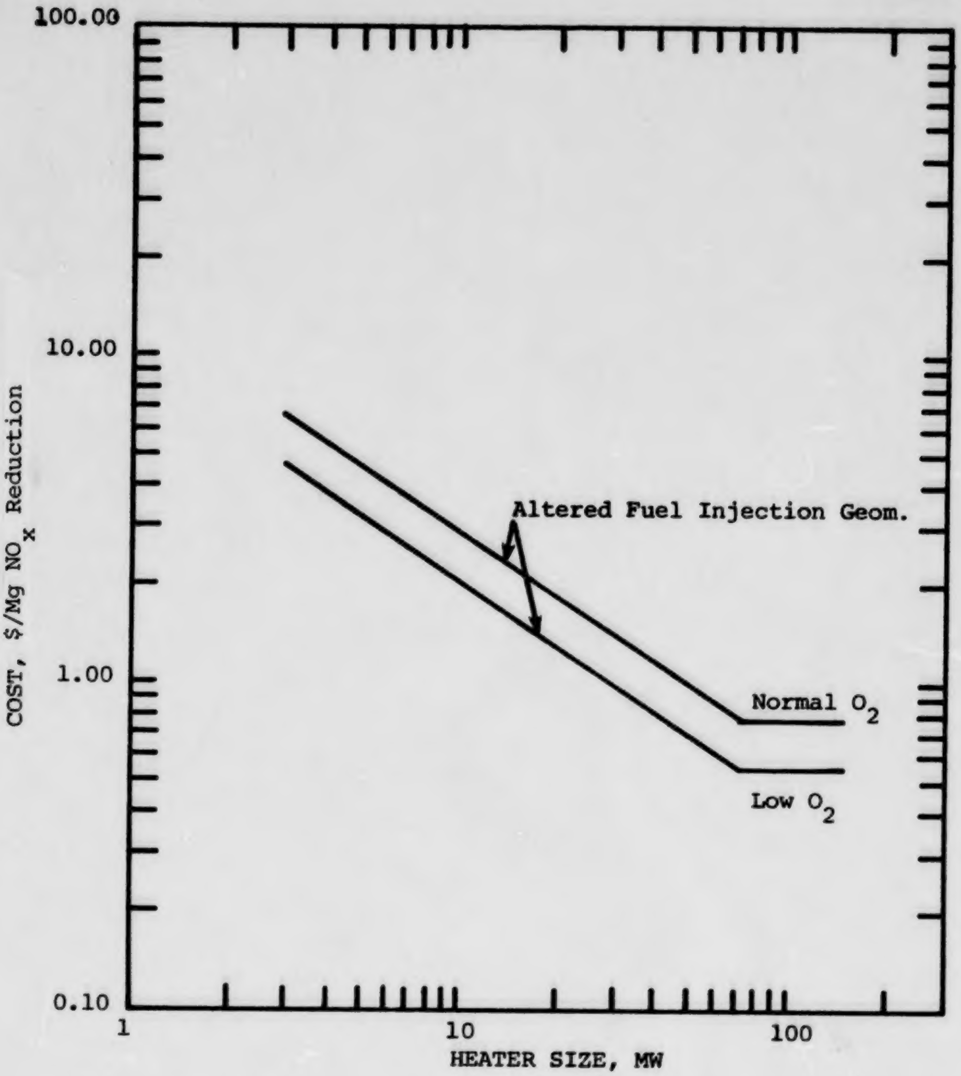


Figure 4-50. Estimated cost as a function of heater size for altered fuel injection geometry modification to natural draft process heaters firing natural gas only.

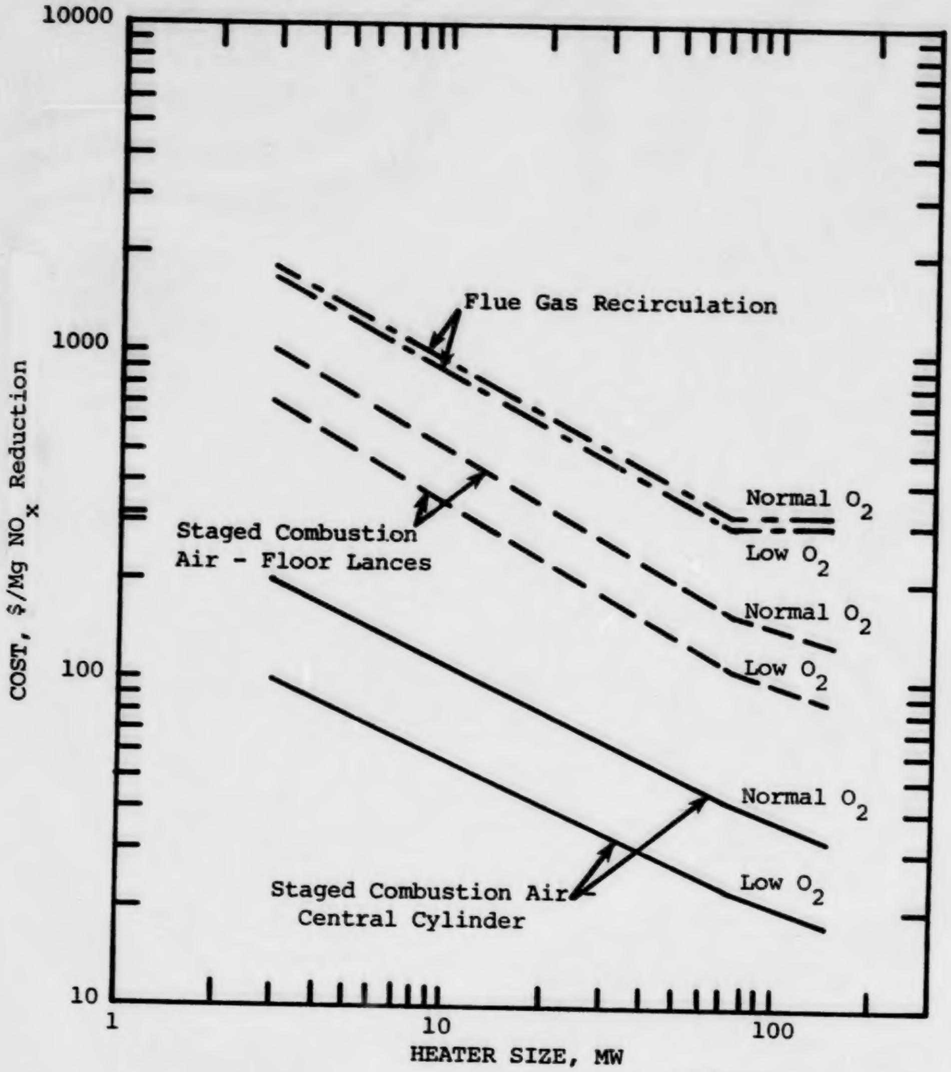


Figure 4-51. Estimated cost as a function of heater size for three combustion modifications to natural draft process heaters firing natural gas only.

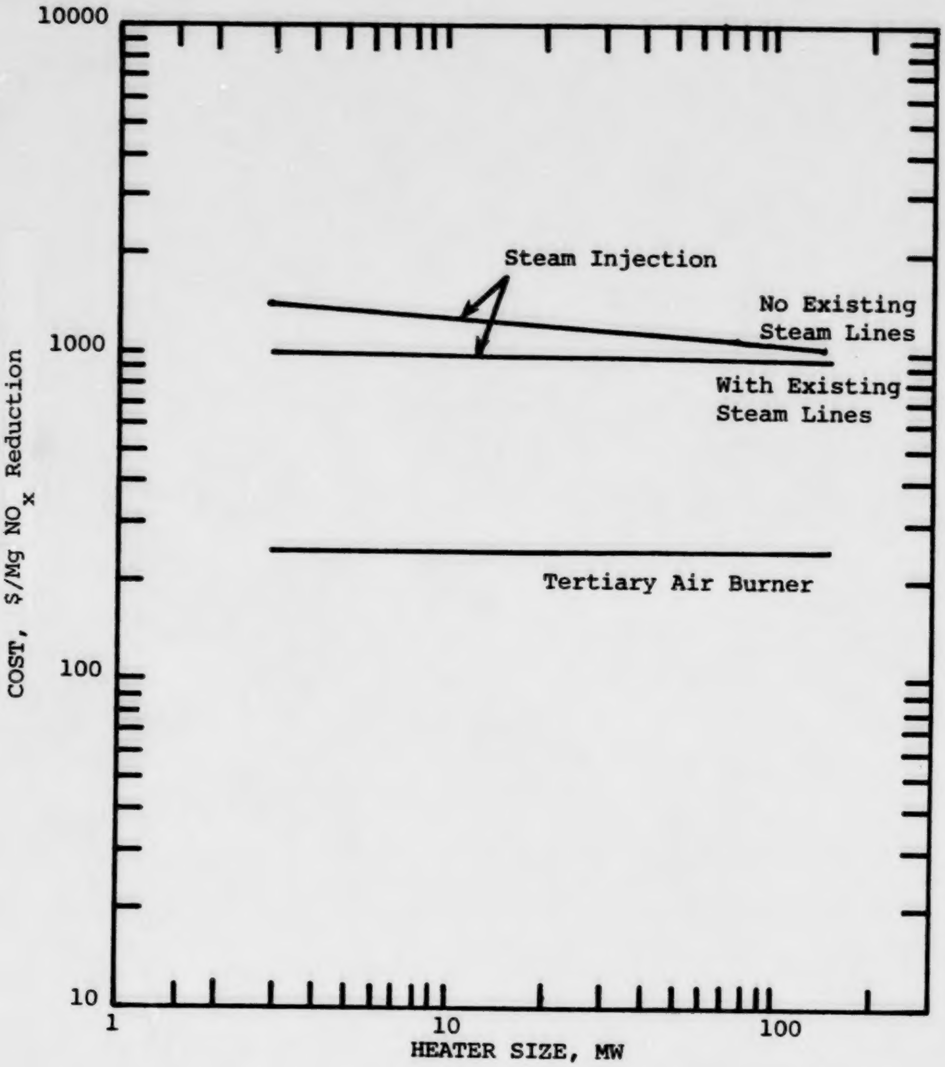


Figure 4-52. Estimated cost as a function of heater size for steam injection modification and for changeover from conventional to tertiary air burner in natural draft process heaters firing natural gas only.

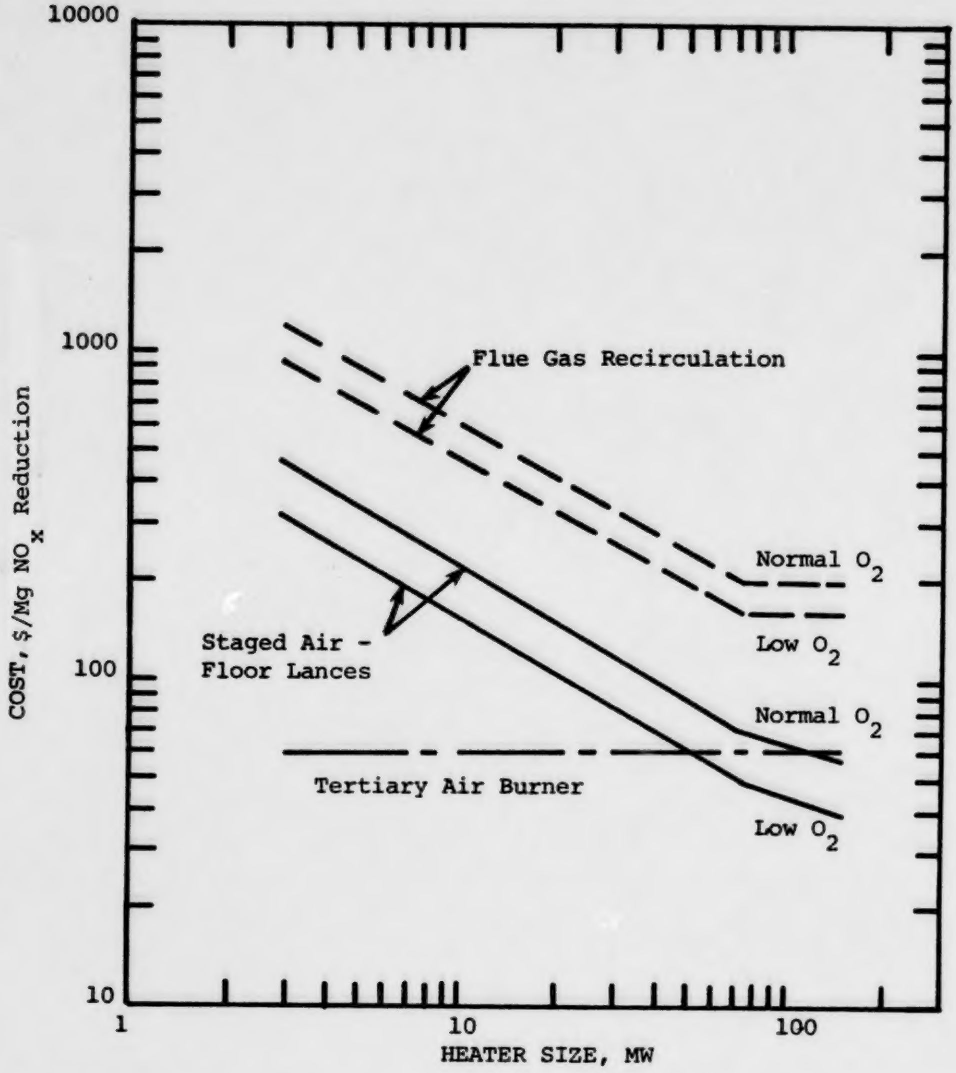


Figure 4-53. Estimated cost as a function of heater size for two combustion modifications and for changeover to tertiary air burner in natural draft process heaters firing No. 6 fuel oil only.

This compares well with the actual value of $18,800 given in Table 4-6 for a 73.3 MW heater.

For heaters larger than 73.3 MW (250 x 10^6 Btu/h), there is greater variability in the cost/size relationship among the various modifications. In all cases, however, total annualized costs increase more rapidly with size than those for heaters between 2.9 MW and 73.3 MW. In the cases of flue gas recirculation and altered injection geometry, the total annualized cost becomes directly proportional to the first power of heater size. For staged combustion air (central cylinder) and staged combustion (lances), the total annualized cost is roughly proportional to heater size to the two-thirds power.

Caution must be used when applying these power laws. They may be used to give a first approximation of modification costs in cases where the modified system incorporates the changes and additions to the original unit outlined in Section 4.5.2 of this chapter.

In Figures 4-54, 4-55, and 4-56, the cost effectiveness versus the potential NO_x reduction possible for each modification is plotted for the three heater sizes. Where two values are plotted for the same modification and the same fuel, the one associated with the larger NO_x reduction corresponds to operation at low excess air and the other corresponds to normal excess air. Where there is only a single value for a particular modification (other than lowered excess air), operation at normal excess air is understood.

4.5.2 Determination of Initial Capital Costs and Annual Operating Costs

1. Lowered Excess Air. There are no initial costs associated with lowered excess air, provided damper controls and accurate oxygen-measuring instruments are available. Measurement of CO is also required.

Zero annual operating costs (or savings) are reported here although some fuel savings results with the use of lowered excess air. There are some probable costs associated with monitoring heaters firing closer to stoichiometric, but these are likely to be small and variable from plant to plant.

2. Flue Gas Recirculation. For the purposes of cost estimating, all burners are assumed to be the same size; i.e., 2.9 MW (10 x 10^6 Btu/h). Thus, the small heater has one burner, the intermediate size has 25 burners,

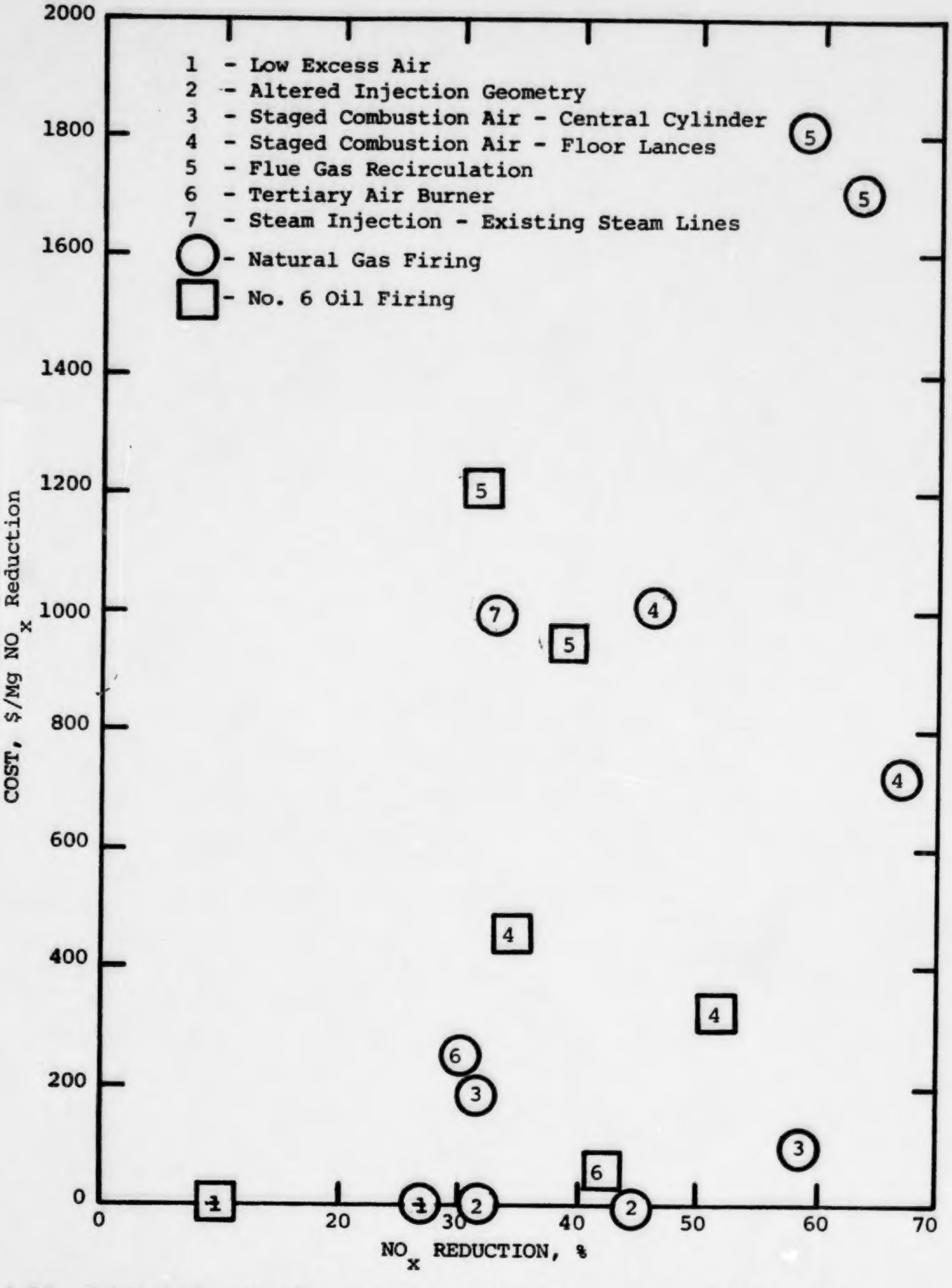


Figure 4-54. Estimated cost of combustion modifications as a function of percent NO_x reduction for a 2.9 MW (10×10^6 Btu/h) process heater.

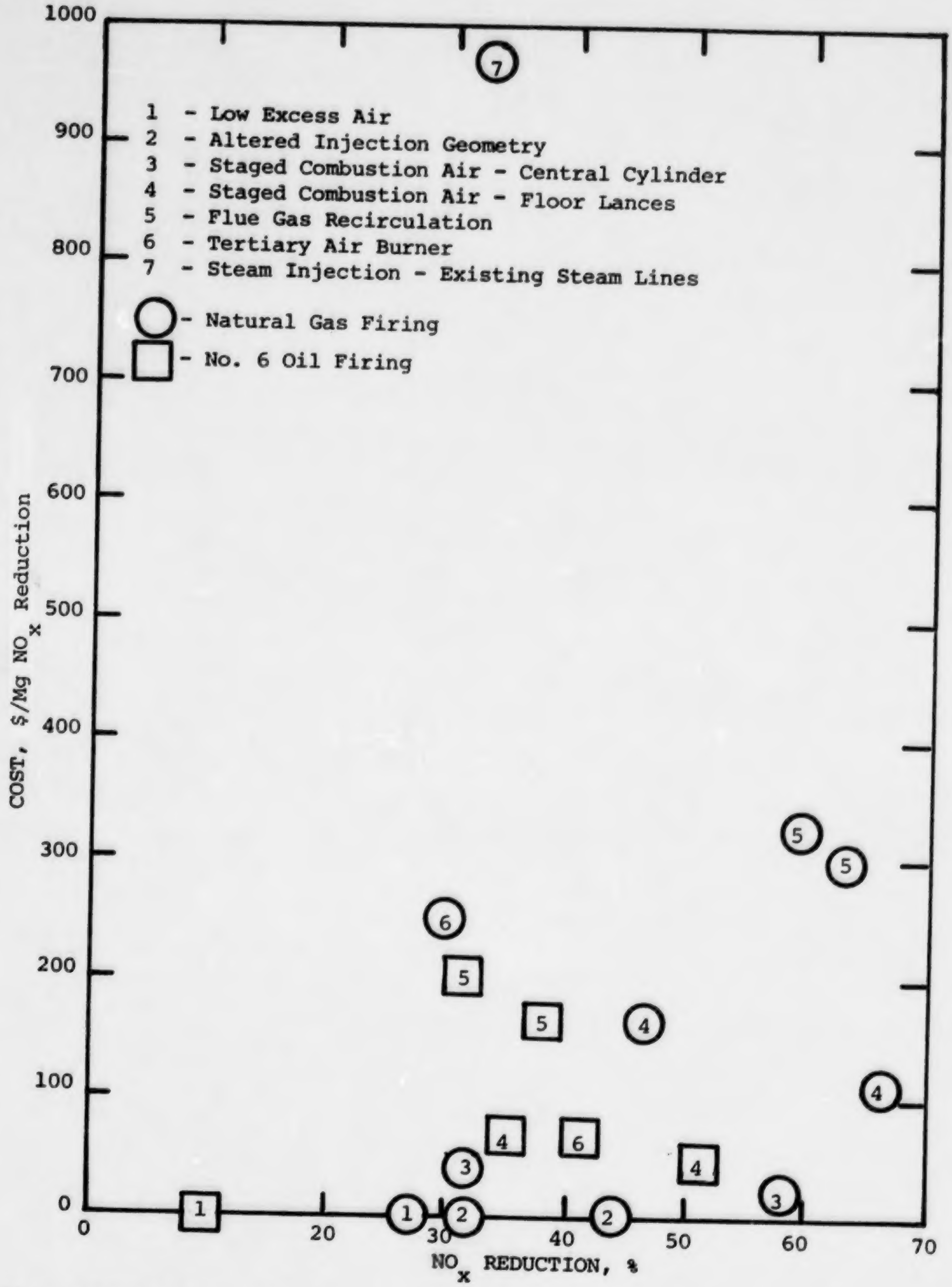


Figure 4-55. Estimated cost of combustion modifications as a function of percent NO_x reduction for a 73.3 MW (250×10^6 Btu/h) process heater.

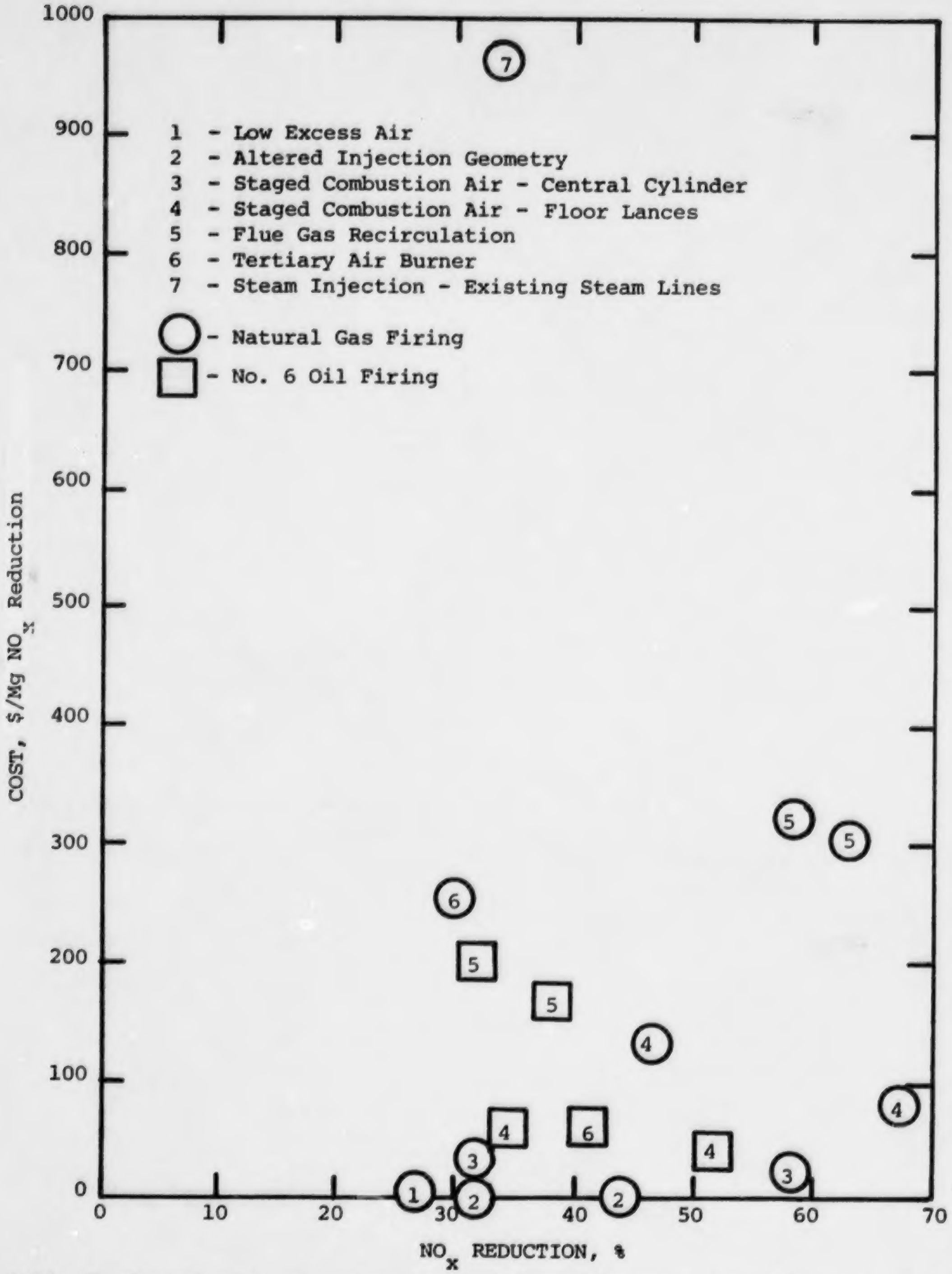


Figure 4-56. Estimated cost of combustion modifications as a function of percent NO$_x$ reduction for a 147 MW (500×10^6 Btu/h) process heater.

and the large heater has 50 burners. The number of burners involved is important in determining lengths of pipe or ductwork required, the number of tees, ells, crosses, etc., for each modification technique.

The initial fixed costs for all modifications were estimated using References 10 to 14 and best judgment. Cost values presented in this section which were determined without reference to published cost data will be identified as such.

For flue gas recirculation, the initial fixed costs were determined as shown in Table 4-7.

TABLE 4-7. INITIAL INSTALLED COSTS (IN $) OF FLUE GAS RECIRCULATION

Item/Heater Size	2.9 MW ($10x10^6$ Btu/h)	73.3 MW ($250x10^6$ Btu/h)	147 MW ($500x10^6$ Btu/h)
Fan, Motor & Drive	2,000	10,000	23,000
Damper	500	500	1,000
Ductwork & Burner Plenum	2,000	10,000	20,000
Duct Insulation	2,000	8,500	15,000
Instrumentation & Control Systems	10,000	15,000	15,000
Engineering/Design	2,000	10,000	20,000
Totals	$18,500	$54,000	$94,000

The fan, motor, and drive costs above were obtained from References 11 and 12 along with fan power requirements and other operating data. Table 4-8 summarizes the cost data on fans applicable to either flue gas recirculation or staged combustion air (lances). These fan sizes and costs are based on the air flow requirements for approximately 30% flue gas recirculation.

Ductwork costs are based on 0.32 cm (1/8") steel duct material, 30 cm x 60 cm (1' x 2'), and 15 m (50') long for the 2.9 MW heater, 30 m (100') long for the 73.3 MW heater, and 60 m (200') long for the 147 MW heater. Based on past experience, the cost per foot of length of ductwork was estimated to be $20. Installation cost of ductwork hangers was assumed to be equal to the cost of the duct material itself.

TABLE 4-8. DELIVERED/INSTALLED* COSTS (IN 1978 $) OF FANS, ASSOCIATED MOTORS, AND DRIVES AND POWER REQUIREMENTS AS A FUNCTION OF GAS TEMPERATURE AND VOLUME FLOW RATE

Gas Temperature K (°F)	Volume Flow m^3/s (SCFM) 470 (1000)	9400 (20000)	18800 (40000)
294 (70)	300/500 (1/2 hp)	1200/1900 (10 hp)	2200/3500 (30 hp)
533 (500)	1000/1600 (1.4 hp)	5600/8900 (25 hp)	14000/22300 (60 hp)
810 (1000)	3500/5600 (8 hp)	17000/27000 (50 hp)	43000/68400 (150 hp)

*Installed values = 1.59 x Delivered Values, Rounded to nearest $100

Installed costs include equipment foundations, electrical, paint and field labor (according to Ref. 10).

In the case of the small heater a burner plenum requires a rather small amount of duct material and installation material and labor. In the larger heaters, however, the plenum may represent a considerable fraction of the overall installation. It must be designed so as to supply the appropriate mixture of the recirculated flue gas and the combustion air to each burner. Thus, in the case of the larger two heaters, the cost of the burner plenum was presumed to be equal to the cost of the ductwork plus the cost of ductwork hangers and installation as a first approximation.

The cost of dampers to control recirculated flue gas flow was assumed to be small and rather independent of heater size up to 73.3 MW (250×10^6 Btu/h). A one-day installation time by two men at $150/man/day was assumed along with $200 in material costs for the smaller two heaters. These values were doubled to arrive at the $1,000 value shown in Table 4-7 for the 147 MW heater.

Cost data on duct insulation was obtained from Reference 10 (pp. 155-6). At $\$3.25/\text{ft}^2$, the insulation cost for the 600 ft^2 of ductwork required for the 73.3 MW (250×10^6 Btu/h) heater was $1,950 in 1968 which, when appreciated at 7%/year for 10 years, is equivalent to approximately $4,000 in 1978 dollars. Labor costs, including a factor for fair working conditions, were approximately $500 in 1978 dollars for the installation of this same amount of ductwork.

The basic cost of the insulation material was doubled in order to include the costs of lagging, studs, and the cost of insulating the plenum not included in the $4,000 figure. Thus, when added to the labor cost a total cost for all insulation material and installation of $8,500 was obtained for the 73.3 MW heater. Since the ductwork area to be insulated increases linearly with heater size for the flue gas recirculation systems envisioned here, the cost of the insulation for the large 147 MW heater was assumed to be roughly double that of the 73.3 MW heater with some allowance for economy of scale. A figure of $2,000 was used for the 2.9 MW heater because of the relative ease of installation and the disproportionately small amount of insulation required for the burner plenum.

Basic controls required for the simplest FGR system are a recirculated gas temperature, indicator, flow indicator, and damper and fan controls (including alarms and an automatic safety shut-off switch). The installed cost of the temperature and flow indicators in 1961 dollars according to Reference 10 (p. 152) is $1,500 not including fixed, variable, and semi-variable costs as defined in that reference. To include those costs the figure of $1,500 was doubled as a first approximation. In 1978 dollars, assuming an average rate of inflation of 6% over the 17-year period, this sum amounts to approximately $8,000. The cost of fan and damper controls and alarms is estimated by KVB to be approximately $2,000, thus bringing the total instrument and control costs to $10,000 for the smallest heater. For the larger heaters, an additional $5,000 was assumed in order to account for the added complexity of those systems.

The engineering/design cost figures were based roughly on the following man-hour requirements estimated by KVB:

2.9 MW (10×10^6 Btu/h)	73.3 MW (250×10^6 Btu/h)	147 MW (500×10^6 Btu/h)
50 m-h at $40/h	250 m-h at $40/h	500 m-h at $40/h

The total fixed initial costs for flue gas recirculation do not include costs for back-up fans or extra controls which might be required in certain applications.

The annual operating costs for flue gas recirculation include only the fan motor electrical requirement and maintenance since annual fuel costs or savings are impossible to project on the basis of the data collected thus far. The amount of electricity used to drive the fan, based on 75% electrical-to-mechanical conversion efficiency and an 80% operating factor, as well as the cost of electricity, based on a price of 4¢/kW-h determined from Reference 13, are tabulated in Table 4-9.

Flue gas recirculation costs in Table 4-6 are based on a 533 K (500°F) flue gas stream. Thus, $400, $7000, and $17,000 are used as annual fan electrical requirements for the small, medium, and large heaters, respectively. The values in Table 4-6 also include annual maintenance costs of 10% of the initial fixed capital costs (in Table 4-5).

TABLE 4-9. ANNUAL FAN ELECTRICAL REQUIREMENTS IN 1000 kW-h AND COSTS (1978$)

Flue Gas Temperature K (°F)	Recirculated Flue Gas Flow m^3/s (SCFM) 470 (1000)	9400 (20000)	18800 (40000)
294 (70)	3.50 ($140)	70.1 ($2803)	210 ($8410)
533 (500)	9.81 ($392)	175 ($7008)	420 ($16819)
810 (1000)	56 ($2293)	470 ($18781)	701 ($28032)

3. Staged combustion air - floor lances. Initial costs for staged combustion air (lances) were determined using data from Reference 10 (pp. 163-173) and some of the cost data developed for flue gas recirculation.

The costs of piping, valves, fittings, and bends were computed separately, and then the costs of staged air fans, dampers, controls, and engineering/design were added. A 7% annual inflation rate was assumed to convert 1968 dollars to 1978 dollars.

The cost breakdown is shown below for the 2.9 MW ($10x10^6$ Btu/hr) heater.

Component	Material	+	Installation	=	Total (1968 $)		1978 $
12 m (40') of 5 cm (2") ceramic pipe (4 pipes at 10' each)	240		60		300		
12 m (40') of 5 cm (2") carbon steel pipe	24		60		84		
6 m (20') of 10 cm (4") carbon steel pipe	40		40		80		
(4) 5 cm (2") control valves	600		48		648		
(1) 5 cm (2") cross	20		15		35		
(4) 5 cm (2") 90° ells	12		36		48		
(4) ceramic-steel fittings (like raised face flange)	14		16		30		
Subtotal				=	1225	→	∿ 2500
Fan							500
Damper							500
Fan & Damper Controls & Air Flow & Temperature Measurements							5000
Engineering/Design							1000
Total				=			$9500

The costs for the 73.3 MW (250×10^6 Btu/h) process heater size were developed in a similar manner as follows:

Component	Material	+	Installation	=	Total (1968 $)		1978 $
61 m (200') of 5 cm (2") ceramic pipe (20 pipes at 10' each)	1200		300		1500		
61 m (200') of 5 cm (2") carbon steel pipe	120		300		420		
15 m (50') of 23 cm (9") carbon steel pipe	250		225		475		
(20) 5 cm (2") control valves	3000		240		3240		
(20) 5 cm (2") tees, unequal	200		320		520		
(20) 5 cm (2") 90° ells	60		160		220		
(20) ceramic-steel fittings (like raised face flange)	70		80		150		
Subtotal				=	7025	→	14000
Fan							2000
Damper							500
Fan & Damper Controls & Air Flow & Temperature Measurements							15000
Engineering/Design							5000
Total				=			$36500

The costs for the 147 MW (500×10^6 Btu/h) heater were determined as follows:

Component	Material	+	Installation	=	Total (1968 $)		1978 $
91 m (300') of 7.6 cm (3") ceramic pipe (30 pipes at 10' each)	3000		600		3600		
91 m (300') of 7.6 cm (3") carbon steel pipe	330		600		930		
30 m (100') of 28 cm (11") carbon steel pipe	600		500		1100		
(30) 7.6 cm (3") control valves	6300		600		6900		
(30) 7.6 cm (3") tees, unequal	500		100		600		
(30) 7.6 cm (3") 90° ells	150		330		480		
(30) ceramic-steel fittings (like raised face flange)	135		180		315		
Subtotal				=	15925	→	32000
Fan							3500
Damper							1000
Fan & Damper Controls & Air Flow & Temperature Measurement							15000
Engineering/Design							7500
Total				=			$59000

The annual operating costs for staged combustion air (lances) excluding fuel costs (savings) are assumed to be negligible for the purposes of this cost estimate. Annual fan electrical requirements and fan maintenance costs are not included in Tables 4-4 and 4-6. The annual flue gas recirculation fan electrical costs for 294 K shown in Table 4-9 may be used to estimate the additional costs. Thus, fan power requirements and maintenance for the 2.9 MW, 73.3 MW, and 147 MW heaters add 1.5%, 7.7%, and 14.3%, respectively, to the costs shown in Tables 4-4 and 4-6 for staged combustion air (lances).

It is possible to design a staged combustion air (lances) modification which does not require a fan but uses natural draft to introduce air into the firebox through the lances. Naturally, such a system would be less expensive than the system considered here, although some further testing would be required to optimize pipe sizes and configurations.

4. Steam injection. For facilities already having steam piped to the burners, the initial fixed costs are assumed to be negligible. For plants in which no steam capability currently exists, the initial costs were determined with the aid of Reference 10 (pp. 163-173) as follows:

2.9 MW (10×10^6 Btu/h) heater

Component	Material	+	Installation	=	Total (1968 $)		1978 $
15 m (50') of 5 cm (2") carbon steel pipe	30		75		105		
(1) 5 cm (2") control valve	150		12		162		
(1) 5 cm (2") 90° ell	3		8		11		
(1) 5 cm (2") tee, unequal	10		16		26		
Subtotal				=	304	→	700
(1) flowmeter (1961 $)	460		150		610 (1961 $)	→	2300
Total				=			$3000

73.3 MW (250×10^6 Btu/h) heater

Component	Material	+	Installation	=	Total (1968 $)		1978 $
152 m (500') of 5 cm (2") carbon steel pipe	300		750		1050		
(26) 5 cm (2") control valves	3900		312		4212		
(25) 5 cm (2") 90° ells	75		200		275		
(25) 5 cm (2") tees, unequal	250		400		650		
Subtotal				=	6187	→	14000
(1) flowmeter							2300
Total				=			$16300

147 MW (500×10^6 Btu/h) heater

Component	Material	+	Installation	=	Total (1968 $)		1978 $
229 m (750') of 5 cm (2") carbon steel pipe	450		1125		1575		
(51) 5 cm (2") control valves	7650		612		8262		
(50) 5 cm (2") 90° ells	150		400		550		
(50) 5 cm (2") tees, unequal	500		800		1300		
Subtotal				=	11687	→	25500
(1) flowmeter							2300
Total				=			$27800

The annual operating cost for the steam injection modification was assumed to be equal to the cost of the steam used. Maintenance was assumed to be a minor cost and, in the case of existing steam capability, zero cost.

The annual steam use was calculated for each heater size assuming an 80% use factor and a 0.01 kg/s (75 lb/h) steam injection rate per burner. The cost of steam was determined by adding together the cost of water and the cost of converting it to steam (assuming a heat requirement of $2.79\text{x}10^6$ J/kg steam (1200 Btu input/lb steam). The cost of water used was a figure obtained from the Los Angeles Department of Water and Power of 34.8 ¢/1000 ft^3. As an example, the annual cost of steam for the 2.9 MW heater is calculated below.

$$\begin{aligned}
\text{Annual Steam Consumption} &= 75\ \text{lb/h} \times 1\ \text{burner} \times 0.80 \times 8760\ \text{h/y} \\
&= 525{,}600\ \text{lb steam/y}
\end{aligned}$$

$$\begin{aligned}
\text{Annual Cost of Water Used} &= 525{,}600\ \text{lb} \times \frac{1\ \text{ft}^3}{62.4\ \text{lb H}_2\text{O}} \times \frac{\$0.348}{100} \\
&= \$29
\end{aligned}$$

$$\begin{aligned}
\text{Annual Cost of Energy to Generate Steam} &= 525{,}600\ \text{lb} \times 1200\ \text{Btu/lb} \times \$2.00/10^6\ \text{Btu} \\
&= \$1262
\end{aligned}$$

$$\text{Total Annual Steam Cost} = \$1262 + \$29 = \$1291 \simeq \$1300$$

The annual steam costs for the 73.3 MW ($250\text{x}10^6$ Btu/h) and 147 MW ($500\text{x}10^6$ Btu/h) were calculated in the same manner as $32,200 and $64,300, respectively.

5. Tertiary Air Burner--The initial costs of a tertiary air burner were estimated on the basis of information obtained from the burner manufacturer which designed the burner (Ref. 14). Using the highest figures given for the cost of each tertiary air burner ($1,500) and multiplying by the number of burners in each heater, the initial installed cost of tertiary air burners was determined. (Capital costs make up about 2/3 of the investment; installation costs make up the balance.

The annual maintenance costs of the tertiary air burner are not expected to be significantly different from the maintenance costs associated with conventional burners. No other annual costs were considered.

6. Altered Injection Geometry--This modification requires very little initial investment or annual expenditure. Only the initial cost of making the necessary minor burner adjustments is included in the present estimate.

7. Staged Combustion Air - Central Cylinder--The initial installed costs of staged combustion air (central cylinder) were calculated as shown in Table 4-10.

TABLE 4-10. INITIAL COSTS OF STAGED COMBUSTION AIR (CENTRAL CYLINDER) MODIFICATION

Item	2.9 MW	73.3 MW	147 MW
Cylinder material	200	3000	5000
Labor to fabricate cylinders	500 (16 m-h at $31.25/h)	1500 (48 m-h at $31.25/h)	2000 (64 m-h at $31.25/h)
Labor to install	300 (10 m-h at $31.25/h)	1000 (32 m-h at $31.25/h)	1500 (48 m-h at $31.25/h)
	1000	5500	8500
	x 1.5	x 1.5	x 1.5
(Includes shipping and handling costs)	$1500	$8250	$12750

Annual operating costs are expected to be negligible for staged combustion (central cylinder).

4.5.3 Conclusions

The most cost-effective combustion modification for NO_x reduction in natural draft process heaters appears to be staged combustion air. The central cylinder technique is the least expensive type of staged air modification, although the largest percent NO_x reduction was obtained using the floor lance technique. Optimization of the central cylinder concept may further improve its NO_x reduction potential, however.

Flue gas recirculation is an effective but more costly modification. Tertiary air burners, altered injection geometry, and steam injection are all moderately effective in reducing NO_x. Steam injection costs were the highest of any modification for large heater sizes. Altered injection geometry in the present form applies only to gas-fired units, although the concept is adaptable to oil firing. Tertiary air burner addition is currently available and represents moderate NO_x reduction capability at moderate cost.

SECTION 5.0

SUBSCALE TEST - ROTARY CEMENT KILN

5.1 INTRODUCTION

KVB completed a series of tests on a small pilot cement kiln. The cement kiln, located at a major cement industry association facility, has a 13 cm (5 in.) ID, 30 cm (12 in.) OD, and is 4.6 m (15 ft) in length. The maximum kiln feed rate is 0.0015 kg/s (12 lb/hr), and the unit has no air preheat capability.

All tests were conducted with natural gas fuel. The objectives of the tests were the following: to determine the effects of (1) sulfur addition either with the fuel or with the feed, (2) water injection at the burner, (3) kiln dust injection at the burner, and (4) fly ash injection at the burner on gaseous emissions, kiln operating conditions (temperature), and clinker quality.

Table 5-1 summarizes the effects of sulfur addition, water injection, and fly ash injection on gaseous emissions and kiln operating temperatures. The analysis of the clinker material from the kiln for each set of conditions was carried out by the cement association, and that information was supplied to KVB in a report which has been reproduced in Appendix B. Essentially, the injection of these materials had little effect on clinker quality according to that report. Excess air changes had more significant effects on the clinker.

5.2 EMISSIONS SAMPLING

All emissions measurements were taken from the center of the dustbox (at the back end of the kiln upstream of the cyclone as illustrated in Fig. 5-1). Flame zone temperature readings were taken with an optical pyrometer, and the cyclone inlet temperature was measured with a thermocouple. Dustbox excess oxygen measurements were verified using a portable oxygen analyzer.

TABLE 5-1. SUMMARY OF GASEOUS EMISSION DATA - LOCATION 2, RESEARCH ROTARY CEMENT KILN[1]

Test No.	Date, 1978	Kiln Feed Rate g/s (lb/h)	Heat Input Rate kW(10^6Btu/h)	O_2 %[2]	CO_2 %[2]	NO_x ppm*	NO_x ng/J	NO ppm*	NO ng/J	CO ppm*	SO_2 ppm*	HC ppm*	S Inj. %[2]	H_2O Inj. %[2]	Kiln Dust Inj. %[2]	Fly Ash Inj. %[2]	Flame Zone Temp. K (°F)	Cyclone Inlet Temp. K (°F)	Comments[3]
2/3-1	8-17	1.06 (8.4)	78.5 (0.268)	0.20	13.4	64	33	64	33	407	36	31	0	0	0	0	1839(2850)	849(1068)	Baseline - LSF
2/3-2				0.15	12.4	1.0	0.5	1.0	0.5	>1727	35	22	7.3	0	0	0	1805(2790)	849(1068)	Sulfur Injection-LSF
2/3-3		↓	↓	0.10	12.4	~1.0	~0.5	~1.0	~0.5	>1722	~860	--	25	0	0	0	1789(2760)	849(1068)	
2/3-4		0.78 (6.2)	79.7 (0.272)	0.20	11.9	0	0	0	0	>1731	685	52	14	0	0	0	1797(2775)	839(1050)	↓
2/3-5	↓	↓	78.5 (0.268)	0.40	11.9	3.1	1.6	2.6	1.3	830	350	--	0	0	0	0	1800(2780)	844(1060)	Sulfur burn-out - LSF
2/3-6	8-18	0.93 (7.4)	75.7 (0.258)	1.8	12.0	66	34	65	33	28	23	77	0	0	0	0	1761(2710)	850(1070)	Baseline - LSF
2/3-7	↓	↓	↓	2.0	11.5	58	30	57	29	19	11	85	8.1	0	0	0	1761(2710)	843(1058)	Sulfur Injection-LSF
2/4-1	8-18	0.45 (3.6)	75.7 (0.258)	2.1	9.9	63	32	44	23	19	0	40	0	0	0	0	1755(2700)	833(1040)	Baseline - HSF
2/4-2		↓		3.75	9.4	--	--	35	18	21	~125	~104	19	0	0	0	1755(2700)	836(1045)	Sulfur Injection-HSF
2/4-3		0.76 (6.0)		3.1	10.2	55	28	47	24	21	17	--	0	0	0	0	1722(2640)	833(1040)	Baseline - HSF
2/4-4	↓	↓	↓	2.4	10.4	52	27	46	24	48	485	134	18	0	0	0	1739(2670)	836(1045)	Sulfur Injection-HSF
2/5-1	8-18	0.76 (6.0)	79.7 (0.272)	2.55	10.2	58	30	45	23	24	66	153	0	0	0	0	1733(2660)	830(1035)	Baseline - HSF
2/5-2			↓	2.05	10.6	51	26	44	23	24	22	104	0	13	0	0	1755(2700)	832(1038)	Water Injection - HSF
2/5-3			79.3 (0.271)	2.2	10.6	58	30	53	27	24	25	88	0	24	0	0	1758(2705)	838(1048)	
2/5-4				2.05	10.6	54	28	45	23	52	27	88	0	59	0	0	1744(2680)	839(1050)	↓
2/5-5	↓	↓	↓	1.7	12.0	63	32	55	28	23	12	99	0	0	0	0	1766(2720)	836(1045)	Baseline - HSF
2/6-1	8-21	0.44 (3.5)	71.7 (0.245)	1.3	11.4	77	40	73	38	32	0	23	0	0	0	0	1755(2700)	805 (990)	Baseline - LSF
2/6-2		0.61 (4.8)	70.9 (0.242)	1.6	11.2	66	34	65	33	28	0	13	0	0	3.1	0	1733(2660)	803 (985)	Kiln Dust Injection - LSF
2/6-3				1.5	11.6	67	34	66	34	23	0	11	0	0	8.6	0	1694(2590)	805 (990)	
2/6-4		↓	↓	1.55	11.2	78	40	73	38	28	0	9	0	0	9.8	0	1678(2560)	803 (985)	↓
2/6-5		0.76 (6.0)	73.3 (0.250)	0.25	12.0	36	19	35	18	226	19	8	0	0	0	0	1761(2710)	816(1010)	Baseline - LSF
2/6-6				0.10	12.2	17	8.8	16	8.2	1068	20	26	0	0	3.4	0	1766(2720)	811(1000)	Kiln Dust Injection - LSF
2/6-7				0.15	12.4	44	23	40	21	1470	24	18	0	0	9.3	0	1772(2730)	808 (995)	↓
2/6-8	↓	↓	↓	0.30	12.8	76	39	72	37	296	0	37	0	0	0	0	1800(2780)	808 (995)	Baseline - LSF
2/7-1	8-21	0.76 (6.0)	73.7 (0.252)	0.4	13.2	103	53	100	51	227	22	21	0	0	0	2.2	1766(2720)	794 (970)	Fly Ash Injection - LSF
2/7-2			74.9 (0.256)	0.3	13.2	91	47	89	46	1077	0	14	0	0	0	6.6	1783(2750)	791 (965)	↓
2/7-3			73.3 (0.250)	0.3	12.8	119	61	116	60	198	11	12	0	0	0	0	1789(2760)	794 (970)	Baseline - LSF
2/7-4			↓	1.5	11.8	82	42	82	42	28	0	21	0	0	0	0	1789(2760)	794 (970)	Baseline - LSF
2/7-5			73.7 (0.252)	1.5	11.7	73	38	73	38	148	0	13	0	0	0	2.4	1791(2765)	800 (980)	Fly Ash Injection - LSF
2/7-6			↓	1.8	11.7	71	37	71	37	38	0	10	0	0	0	7.3	1755(2700)	794 (970)	↓
2/7-7	↓	↓	73.3 (0.250)	1.6	11.6	99	51	96	49	202	0	13	0	0	0	0	1778(2740)	794 (970)	Baseline - LSF

[1] Natural gas fuel used for all tests.

[2] Percent by mass of kiln feed rate

[3] LSF = Low-Sulfur Feed; HSF = High-Sulfur Feed

*dry, corrected to 3% O_2

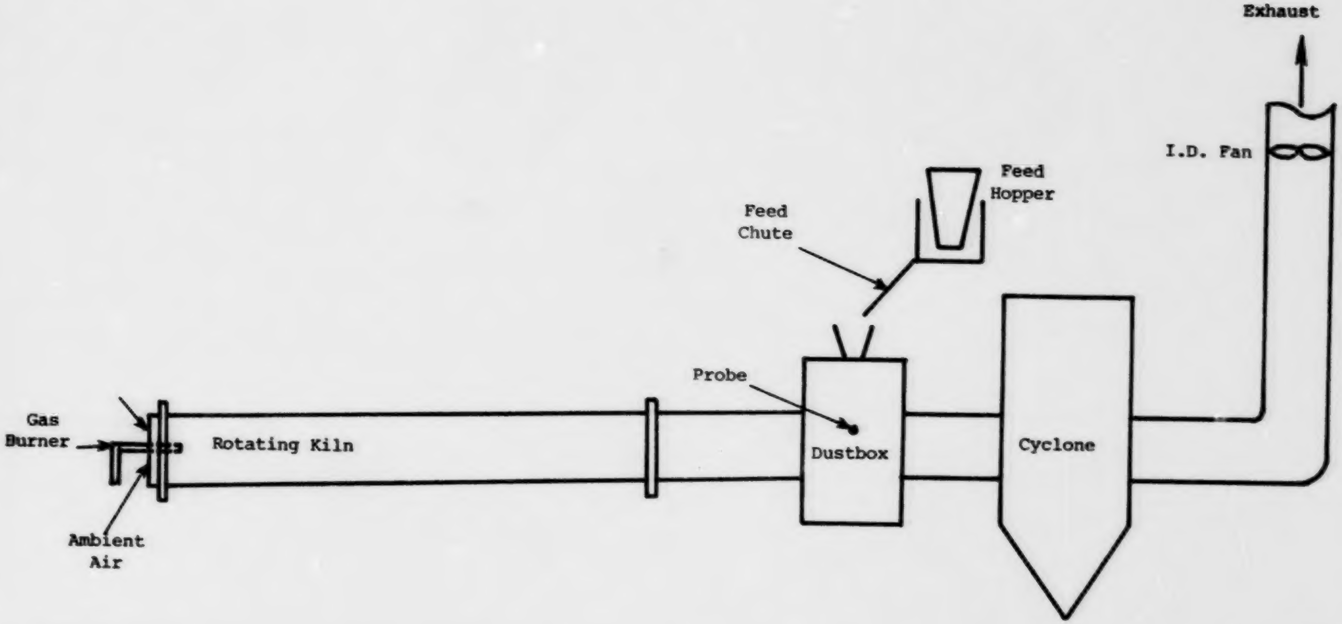

Exhaust
I.D. Fan
Feed
Hopper
Feed
Chute
Probe
Gas
Burner
Rotating Kiln
Dustbox
Cyclone
Ambient
Air

Figure 5-1. Schematic of subscale dry process rotary cement kiln (not equipped with air preheat).

The kiln feed used in the tests was pelletized from a difficult-to-burn mix. This mix was high in limestome content and contained a relatively large amount of binder material to lower the dust loading. The hard-burning mix was selected so that flame zone temperatures would be abnormally high, thus providing a worst-case situation from the standpoint of NO_x emissions.

The fuel analysis for all tests is given in Table 5-2 below.

TABLE 5-2. NATURAL GAS FUEL ANALYSIS (TYPICAL)

Component	Volume %
Nitrogen	1.7
Hydrogen	0.1
Carbon Dioxide	0.5
Methane	95.0
Ethane	2.0
Propane	0.5
Butane	0.2
High Heating value, dry, J/m^3 (Btu/CF)	37.89×10^6 (1017)
Specific gravity	0.5816

The following sections discuss each of the combustion modifications and the results obtained.

5.3 COMBUSTION MODIFICATION

5.3.1 Sulfur Addition

Sulfur was injected with the fuel at different rates for two different feed sulfur contents. The sulfur was injected through a screw feeder and blown in with air. The sulfur injection rate was determined after each test by measuring the total mass of sulfur injected and the time taken to inject it.

Under ordinary operating conditions, the dustbox oxygen is maintained at 1.0% to 2.0%. At approximately this oxygen level the maximum NO_x reductions were ∿20% below a baseline value of 63 ppm (dry, corrected to 3% O_2) with the higher sulfur feed (0.99% SO_3 by weight) and 12% below a baseline of 66 ppm (dry, corrected to 3% O_2) with the lower sulfur feed (0.53% SO_3). The NO_x levels at this O_2 level did not appear to be affected by the change in feed sulfur content although a greater proportion of the total NOx occurred as NO_2 (∿12%) with the high-sulfur feed. The injection of sulfur produced significant increases in SO_2 emissions when the sulfur injection rate was greater than 10% of the kiln feed rate.

At lower dustbox oxygen ($\leq$ 0.4%) the NO_x dropped sharply on the low-sulfur feed. A full 100% reduction in NO_x concentration was observed at 0.2% O_2 on the low-sulfur feed. At the same time, SO_2 emissions increased from a baseline level of 36 ppm (dry, corrected to 3% O_2) to 685 ppm (dry, corrected to 3% O_2). The large decrease in NO_x emissions may be partially a result of oxygen consumption by sulfur (to form SO_2). However, the decrease in NO_x may also have been caused by a drop in oxygen which occurred during the test. The O_2 values reported in Table 5-1 for Tests 2/3-1 to 2/3-5 are nominal values; the lag time ∿ 60 sec in measuring the oxygen concentration may have resulted in readings which did not match kiln conditions precisely. [In tests subsequent to the sulfur injection tests it was determined that small changes in oxygen concentration at low (< 0.5%) produced significant changes in NO_x emissions. Special effort was made in those latter tests to hold oxygen levels constant.]

At the low oxygen conditions with the low-sulfur feed, CO concentrations went off scale (> 2000 ppm) during sulfur injection, up from an initial baseline at 0.20% O_2 of 407 ppm (dry, corrected to 3% O_2). At higher oxygen conditions, CO concentrations were generally < 30 ppm.

Figures 5-2 and 5-3 graph the relationship of NO_x emissions to (1) dustbox oxygen, and (2) sulfur injection rate for the two different kiln feed contents. (Low-O_2 conditions were not tested with the high-sulfur feed because of a shortage of feed.) Figure 5-4 shows NO_x emissions versus SO_2 emissions. However, no direct relationship between the two is implied by this graph.

5.3.2 Water Injection

Water was sprayed into the flame zone at three different flow rates for one feed sulfur content and at approximately 2% oxygen. Water was metered through a pipette and entered the kiln through a pipe next to the burner pipe.

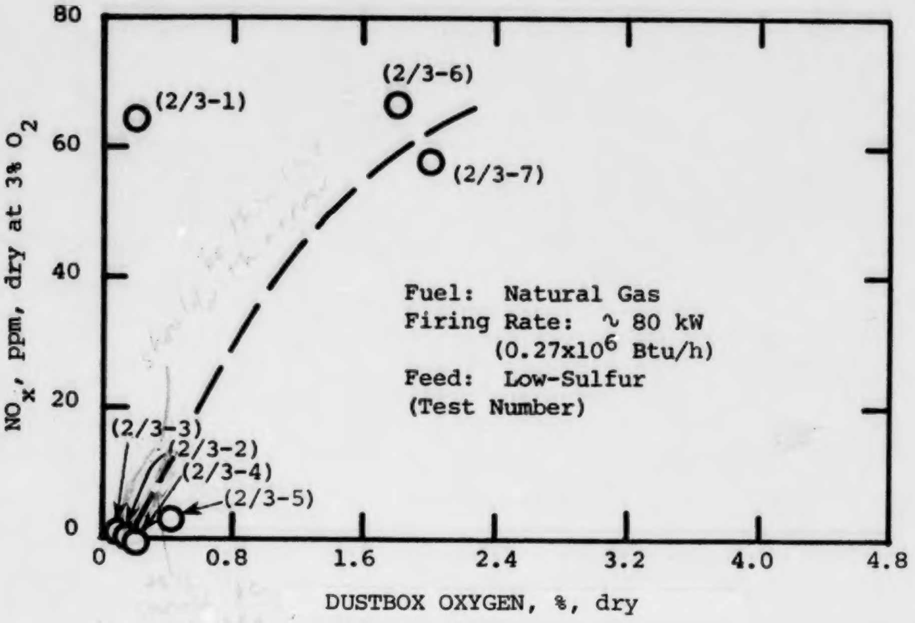


Figure 5-2a. NO$_x$ emissions as a function of dustbox oxygen for a research cement kiln with low-sulfur kiln feed.

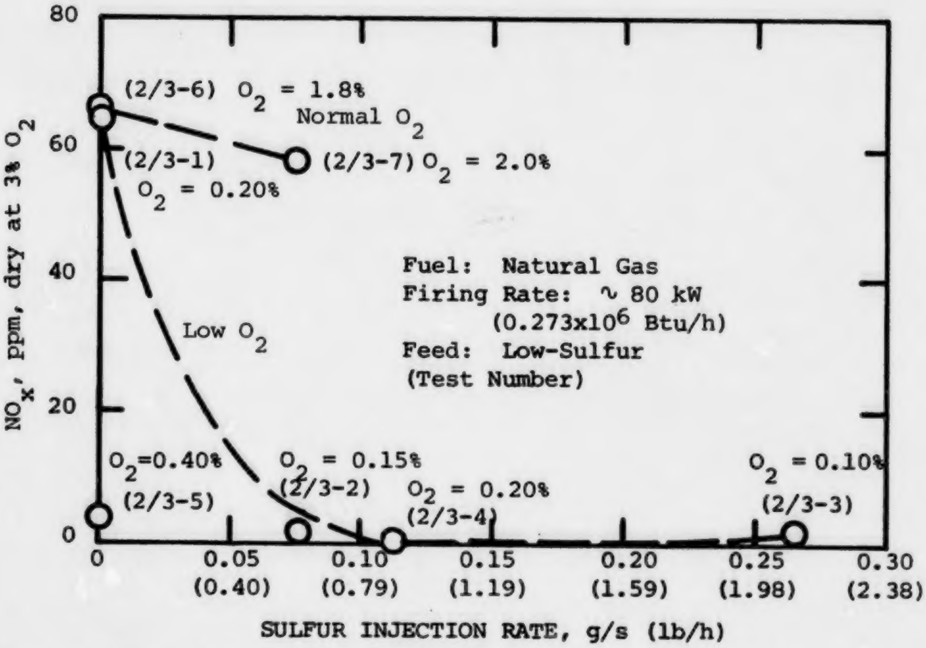


Figure 5-2b. NO$_x$ emissions as a function of sulfur injection rate for a research cement kiln with low-sulfur kiln feed.

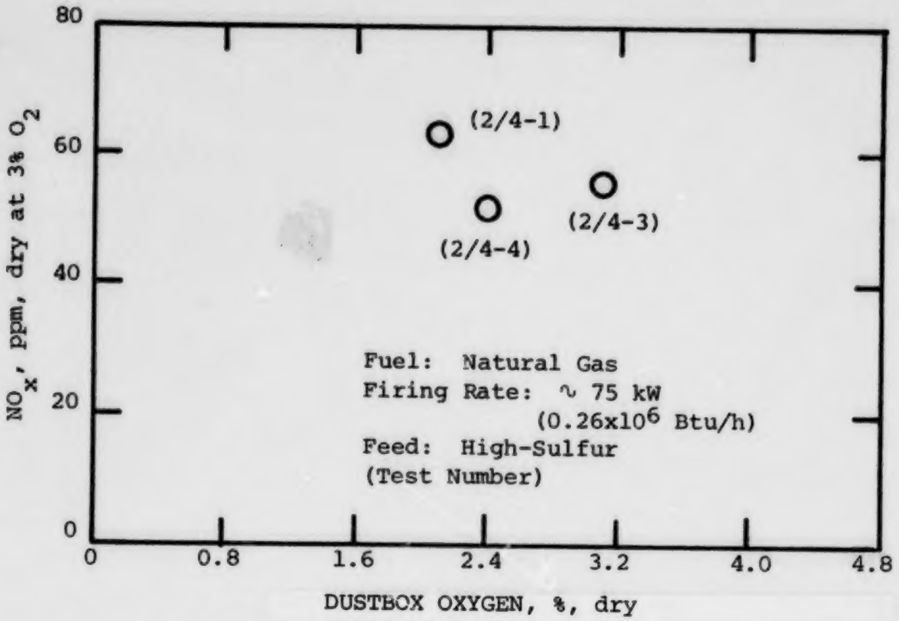


Figure 5-3a. NO_x emissions as a function of dustbox oxygen for a research cement kiln with high-sulfur kiln feed.

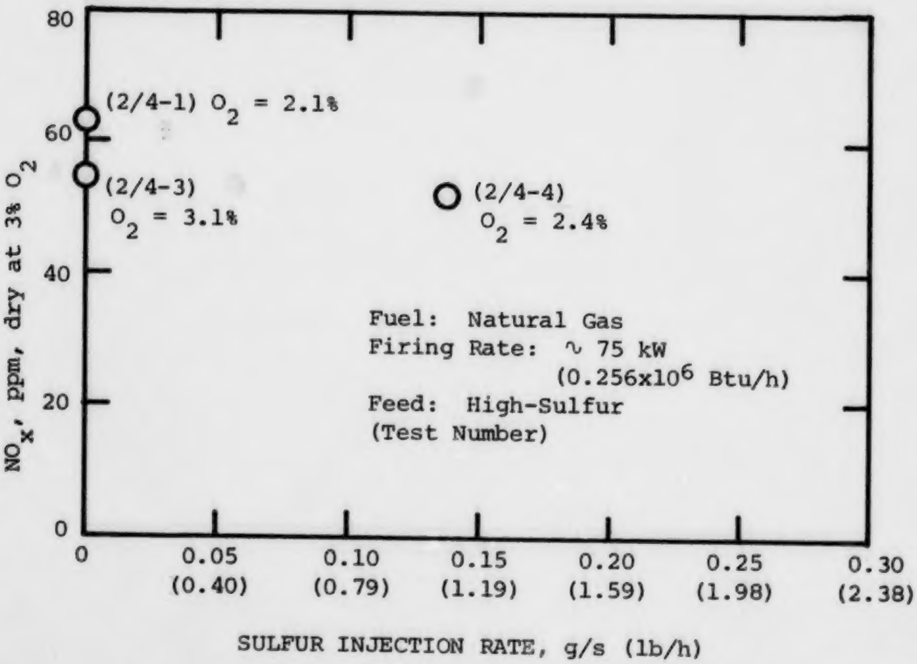


Figure 5-3b. NO_x emissions as a function of sulfur injection rate for a research cement kiln with high-sulfur kiln feed.

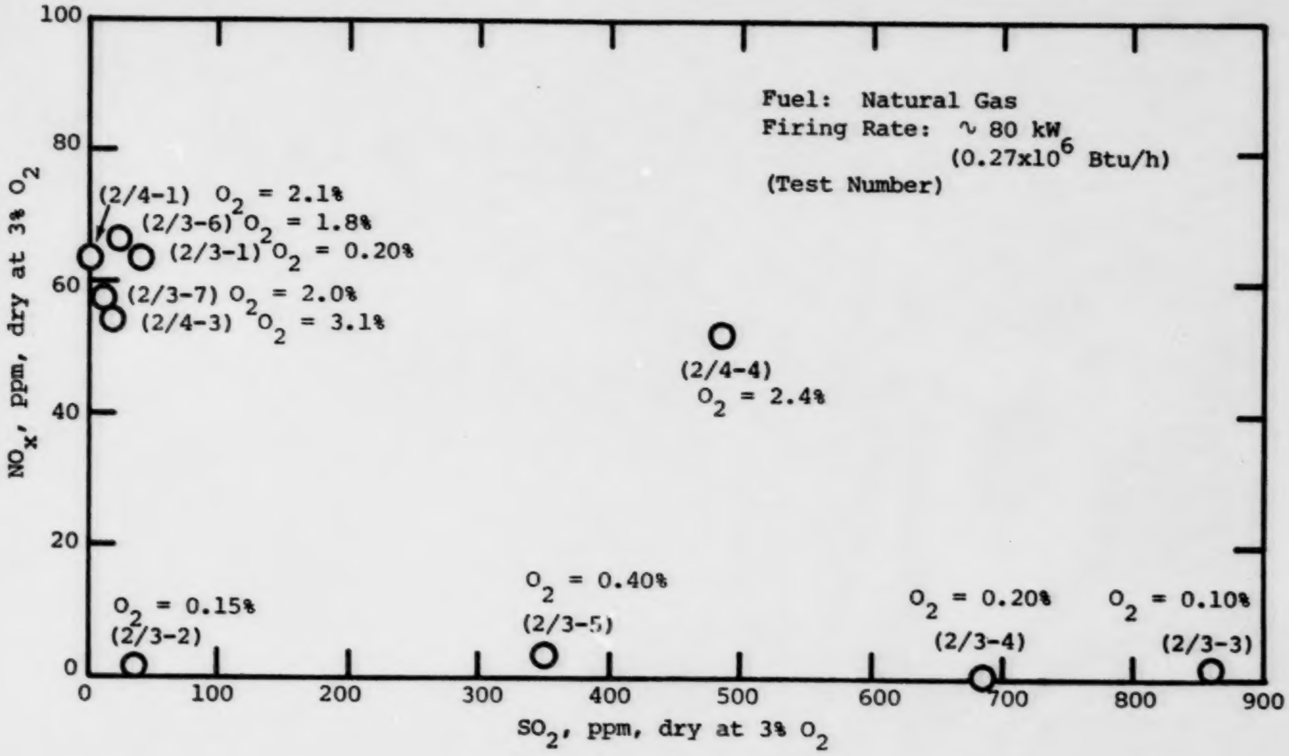


Figure 5-4. NO_x emissions as a function of SO_2 emissions for several sulfur addition rates and dustbox oxygen conditions.

Small reductions in NO_x of 12-14% below baseline levels of 58-63 ppm (dry, corrected to 3% O_2) occurred during the water injection tests. The NO_x concentration did not appear to vary significantly with the water injection rate. At the highest injection rate, however, the CO concentration was twice the baseline value (52 ppm, dry, corrected to 3% O_2 up from 24 ppm, dry, corrected to 3% O_2).

Figure 5-5 shows the relationship between NO_x emissions and water injection rate at a nominal O_2 level of 2% for the high-sulfur kiln feed.

5.3.3 Kiln Dust Injection

Kiln dust containing 6.76% sulfur (by weight) was injected at various rates and at two different oxygen conditions while burning the low-sulfur kiln feed. The injection technique was the same as that used for sulfur addition.

At a baseline oxygen level of approximately 1.5%, the maximum NO_x reduction of 14% below the baseline of 77 ppm (dry, corrected to 3% O_2) occurred with the lowest rate of the kiln dust injection (approximately 3% of kiln feed rate). Increases in dust injection rate caused the NO_x to increase rather than decrease. CO, SO_2, and hydrocarbon emissions were all very low at this O_2 level.

At the low oxygen conditions, the maximum reduction of NO_x again occurred at the smallest kiln dust injection rate (again approximately 3% of kiln feed rate). This reduction, however, was accompanied by a slight drop in oxygen similar to the drop which occurred during the sulfur injection tests. Thus, changes in O_2 may have been responsible, at least in part, for the reduction in NO_x concentration observed at less than 0.3% oxygen.

During the dust addition at the low O_2 levels the CO concentration rose to greater than 1000 ppm. SO_2 and hydrocarbon concentrations were low, however, although they were slightly higher than they had been at the higher O_2 condition.

Figure 5-6 graphs NO_x emissions versus dustbox oxygen and kiln dust injection rate.

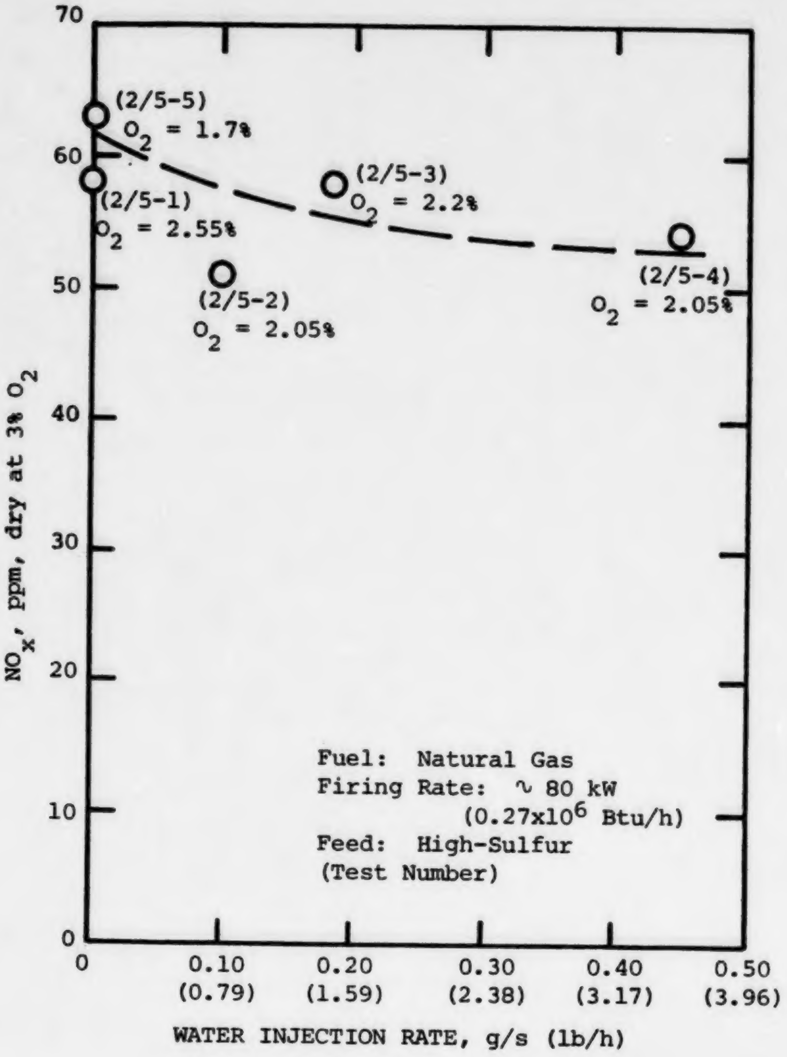


Figure 5-5. NO$_x$ emissions as a function of water injection rate for a research cement kiln.

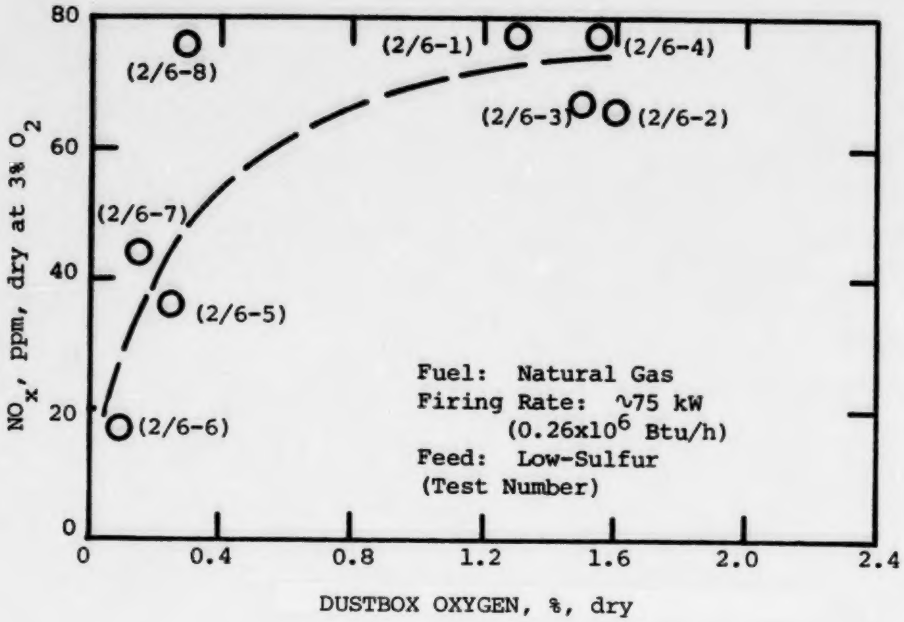


Figure 5-6a. NO_x emissions as a function of dustbox oxygen for a research cement kiln.

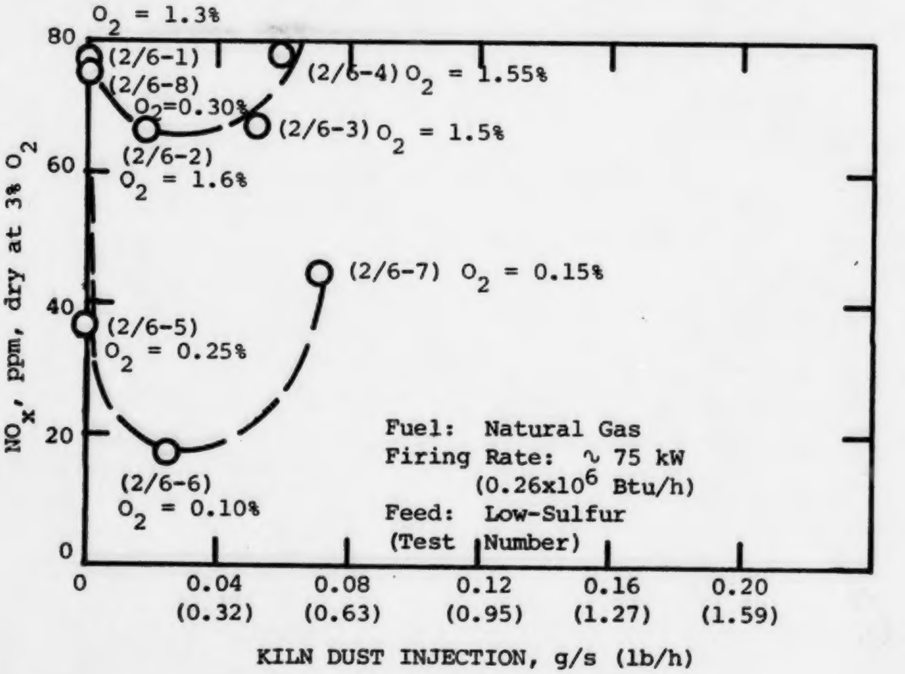


Figure 5-6b. NO_x emissions as a function of kiln dust injection for a research cement kiln.

5.3.4 Fly Ash Injection

Fly ash containing 0.16% sulfur by weight was injected at various rates and at two different oxygen levels while firing the low-sulfur feed. The injection method was that used for sulfur and kiln dust addition. Figure 5-7 shows the effects on NO_x emissions of fly ash injection rate and dustbox oxygen.

At the baseline oxygen level of approximately 1.5%, the maximum NO_x reduction of 28% below a baseline of 99 ppm (dry, corrected to 3% O_2) occurred at the maximum fly ash injection rate (approximately 7% of kiln feed rate). CO concentrations rose somewhat during fly ash injection to 100-200 ppm from a baseline level of 28 ppm (dry, corrected to 3% O_2) . Other emissions were low.

At low oxygen conditions (approximately 0.3%) NO_x values dropped a maximum of only 24% from a baseline level of 119 ppm (dry, corrected to 3% O_2). This reduction occurred at the greatest fly ash injection rate (again, approximately 7% of kiln feed rate). The CO concentration rose to 1077 ppm (dry, corrected to 3% O_2) from a baseline value of 198 ppm (dry, corrected to 3% O_2). SO_2 and hydrocarbon emissions were low.

Special effort was made during the fly ash injection tests to maintain constant oxygen levels throughout and, especially, to prevent the oxygen concentration from dropping below 0.3% at the low O_2 condition. The results showed that NO_x reduction potential may not be any greater at very low O_2 than it is at the baseline O_2 level.

5.4 CONCLUSIONS

Operation of the cement kiln at very low oxygen levels (below 0.5%) does not seem to be practical. Very low NO_x levels may be attained, but the accompanying CO concentrations are high. In addition, when special care was taken to hold the oxygen level constant, the results indicated that a modification applied at baseline O_2 (approximately 1.5%) has nearly the same effect on NO_x emissions when applied at low O_2 conditions.

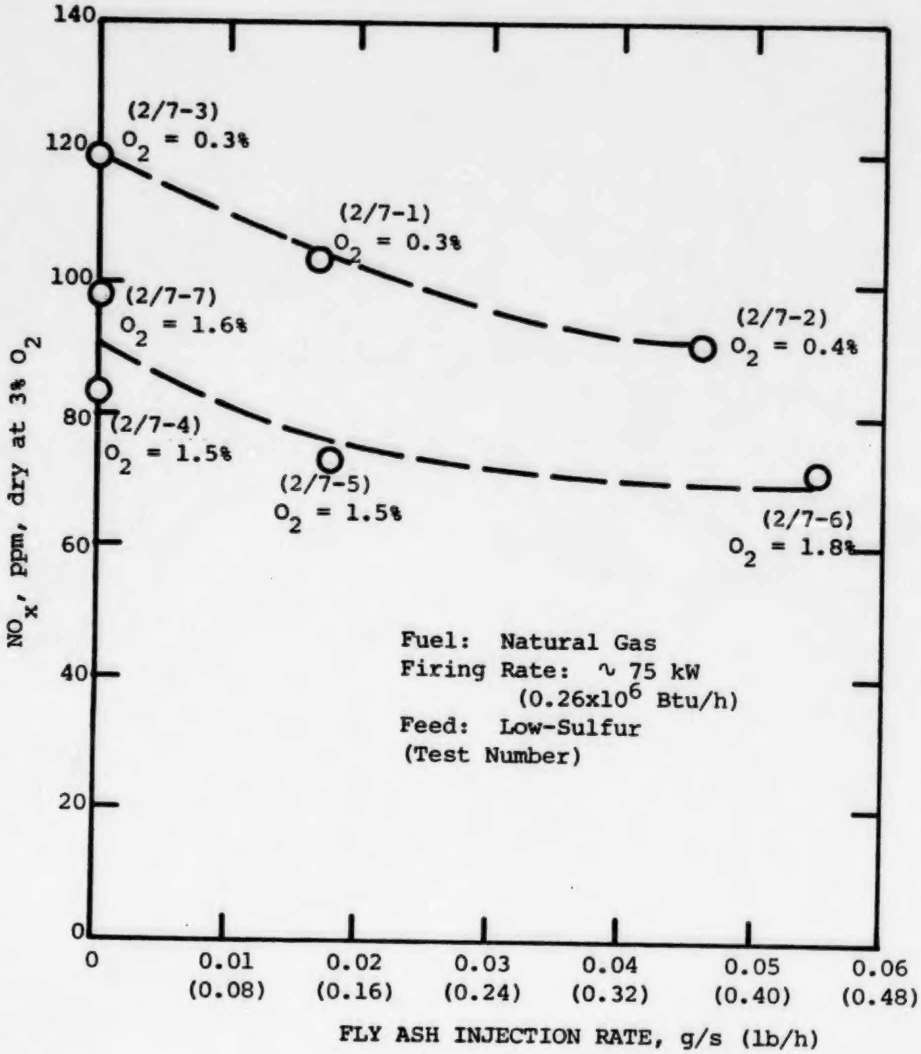


Figure 5-7. NO$_x$ emissions as a function of fly ash injection rate at baseline and low oxygen conditions.

The maximum practical NO_x reductions attained in the research kiln are shown in Table 5-3. These reductions all occurred at baseline oxygen conditions. Sulfur, water, and kiln dust injection seem to produce similar results. Fly ash injection produced the largest practical NO_x reduction.

TABLE 5-3. MAXIMUM PRACTICAL NO_x REDUCTIONS FOR FOUR COMBUSTION MODIFICATIONS TO A RESEARCH CEMENT KILN

Combustion Modification	Maximum NO_x Reduction (%)
Sulfur Injection	12 - 20
Water Injection	14
Kiln Dust Injection	14
Fly Ash Injection	28

It is important to note that the baseline NO_x levels observed for the pilot kiln were far lower than any observed by KVB on full-scale kilns. The most likely explanation for this occurrence is the fact that ambient air was used in all of the subscale tests. In an actual kiln, air preheat temperatures of 1144 K (1600°F) are not uncommon. The report in Appendix B suggests in addition that the high surface-to-volume ratio may have resulted in greater heat losses from the flame zone, thus lowering NO_x production and also that the high gas-to-solids ratio in the subscale kiln limited the effect of kiln feed nitrogen on the NO_x emissions.

SECTION 6.0

SUBSCALE TEST, STEEL FURNACE

This section deals with the emissions and efficiency testing of a small research steel furnace with a maximum firing rate of 0.6 MW ($2x10^6$ Btu/hr) located at the test facility of a major manufacturer of steel furnace burners. Both natural gas fuel and No. 2 oil were fired in a standard radial/axial burner provided by the manufacturer. A schematic of the experimental apparatus is presented in Figure 6-1.

6.1 TEST APPARATUS AND EMISSIONS SAMPLING

The test apparatus consisted of a burner firing into a test furnace with provisions for flue gas, steam, and water to be introduced into the burner flame (see Figure 6-1).

The test furnace served as a combustion chamber with a residence time of about two seconds when firing at 0.6 MW. The furnace can operate at 1978K (3100°F) and is outfitted with numerous access ports for visual observation and temperature measurement. The furnace temperature was maintained at 1533K (2300°F) throughout the test by exposing more or less of the water cooled probes to the furnace interior. This was done to simulate desired conditions in an actual furnace.

The 0.6 MW ($2x10^6$ Btu/hr) burner of the axial-radial type was used to simulate the commonly used 2.4 MW ($8x10^6$ Btu/hr) version. The burner can be fired on natural gas, No. 2 fuel oil, or both simultaneously. When firing on gas, the unused oil port was used for water injection. When firing on oil, one of the unused gas ports was used for steam injection.

The introduction of flue gases into the burner flame was accomplished by passing a portion of the furnace exhaust's flue gases by means of a blower

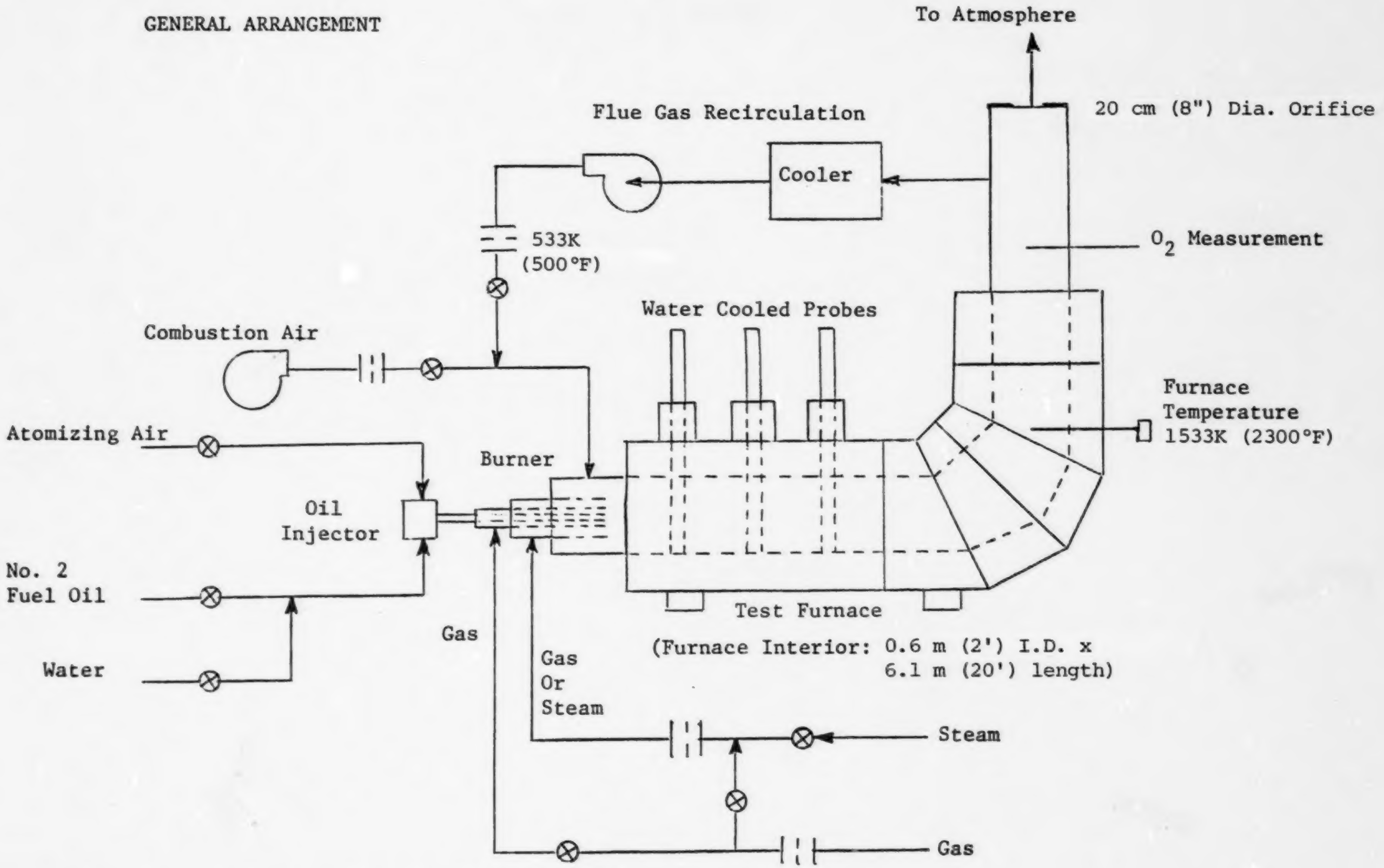

GENERAL ARRANGEMENT
To Atmosphere
20 cm (8") Dia. Orifice
Flue Gas Recirculation
Cooler
O_2 Measurement
533K
(500°F)
Water Cooled Probes
Combustion Air
Furnace
Temperature
1533K (2300°F)
Atomizing Air
Burner
Oil
Injector
No. 2
Fuel Oil
Test Furnace
Gas
(Furnace Interior: 0.6 m (2') I.D. x
6.1 m (20') length)
Water
Gas
Or
Steam
Steam
Gas

Figure 6-1. Subscale steel furnace test schematic.

through a stainless steel air-to-air cooler and combining this flow with the combustion air flow. The temperature of the recycled flue gases was maintained at ~533K (500°F) by adjusting the flow of cooling air through the cooler. Good mixing of the combustion air and flue gases was assured by employing a diffuser between the combustion air/flue gas plenum and the burner.

A 20-cm (8-inch) diameter orifice was added to the furnace exhaust stack to stop ambient air entrainment in the exiting flue gases resulting in inaccurate flue gas O_2 readings and place the furnace and the flue gas recirculation (FGR) ductwork under positive pressure to reduce the infiltration of ambient air through the cooler and blower.

All gas flows (combustion air, FGR, steam, atomizing air, and natural gas) were measured with the aid of orifices and manometers and are considered to be accurate to within 5 percent. All liquid flows (No. 2 fuel oil and water) were measured with rotameters which had been calibrated with the fluid to be measured.

The gas samples were taken from the exhaust stack with an aspirated stainless steel tube. The flue gas samples were pumped to continuous gas analyzers housed in the KVB mobile laboratory.

The installation of an O_2 analyzer in the FGR ductwork just upstream of the combustion air plenum became necessary to determine the degree of flue gas dilution with infiltrating ambient air.

Temperature measurements of all flows, including the flue gas temperature, were made using type "K" (61K to 1589K) thermocouples. Flame temperature profiles were obtained using a type "R" (256K to 2033K) aspirated thermocouple.

Gaseous emissions were measured at baseline conditions and at various excess air settings at full capacity and half capacity (nominally). In addition to excess air variation, steam injection and water injection were tried at full capacity firing No. 2 oil and natural gas, respectively, to reduce NO_x emissions. Flue gas recirculation was also tested firing each of the two fuels. The FGR rates reported in this section were calculated according to the expression used in Section 4, page 4-54 for process heaters.

4-54

Flame temperature profile measurements were made for each of the modified conditions as well as for baseline conditions firing both natural gas and No. 2 oil. All the data obtained from the subscale steel furnace tests are presented in Appendix C.

6.2 COMBUSTION MODIFICATIONS

The overall results of the combustion modification tests are most encouraging from the standpoint of NO emission reduction potential. The average baseline NO_x emission for a steel furnace burner firing natural gas and No. 2 oil is given in Table 6-1. The maximum NO reductions obtained for each modification are summarized in Table 6-2.

Figures 6-2 and 6-3 show the effect of oxygen on NO emissions when firing natural gas and No. 2 oil. For both fuels NO emission peaks at about 2% O_2. As the O_2 was increased beyond 2%, the NO concentration tended to decrease. The NO concentration also decreased at O_2 levels below 2%, but the trend is less pronounced. (The high furnace temperatures which occurred at low O_2 conditions on several occasions caused NO emission at these conditions to be higher than it would have been if the temperature had been held constant.)

There is an apparent considerable spread in the data for NO emissions versus stack oxygen. Figures 6-2 and 6-3 suggest a family of curves for NO vs. O_2. This indicates that another important factor is involved in determining NO levels. It is believed that this factor is the combustion air humidity and that each curve in the "family" of curves represents a constant air moisture content. Unfortunately, precise moisture data were unavailable at the test site. Dry bulb and relative humidity data were obtained from a weather station approximately ten miles from the test site. These data were used in the construction of Figures 6-4 and 6-5. The moisture in the combustion air was added to the water injected through the burner in these figures.

TABLE 6-1. AVERAGE BASELINE NO_x EMISSION, SUBSCALE STEEL FURNACE BURNER

(Including All Baseline Tests at Location 4)

Fuel	NO_x ppm*	NO_x ng/J	Number of Tests	Coefficient† of Variation
NG	222	114.6	11	0.19
No. 2	277	153.4	8	0.23

*ppm corrected to 3% O_2, dry

†Coefficient of variation = $\frac{\text{Std. deviation}}{\text{Mean}}$

TABLE 6-2. SUMMARY OF SIGNIFICANT TEST RESULTS, SUBSCALE STEEL FURNACE BURNER

Test Number	Fuel	Combustion Modification	Firing Rate (% Cap.)	O_2 %	NO (ppm)*	% Reduction in NO From Nearest Baseline
4/3-11	NG	Water Injection	100	2.2	98	47
4/4-13	NG	FGR	100	2.0	38	88
4/3-12	NG	FGR + Water Inj.	100	1.8	24	87
4/7-2	No.2	Steam Injection	100	2.1	24	89
4/8-10	No.2	FGR	100	2.0	57	77

*NO corrected to 3% O_2, dry

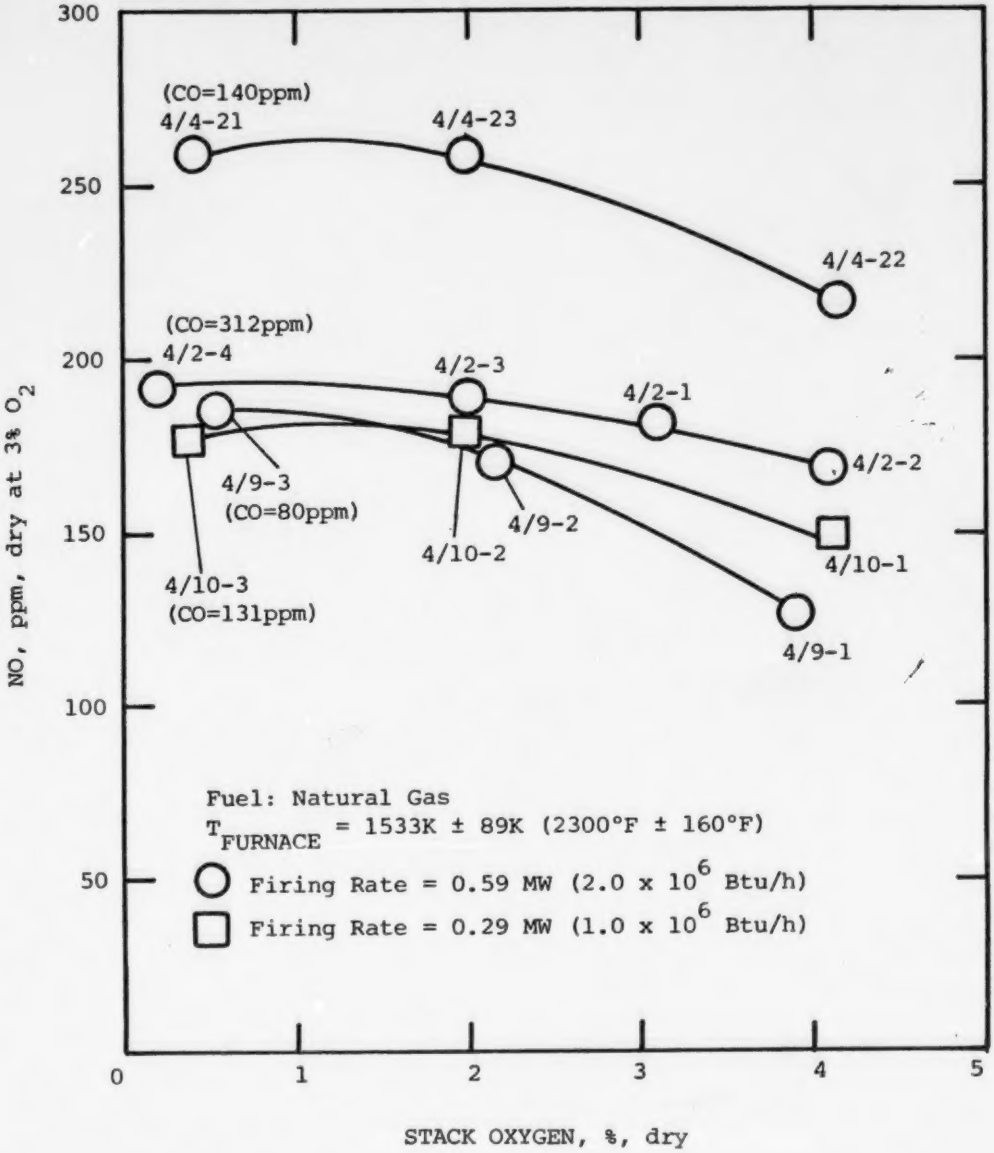


Figure 6-2. NO emission as a function of stack oxygen for a subscale steel furnace firing natural gas.

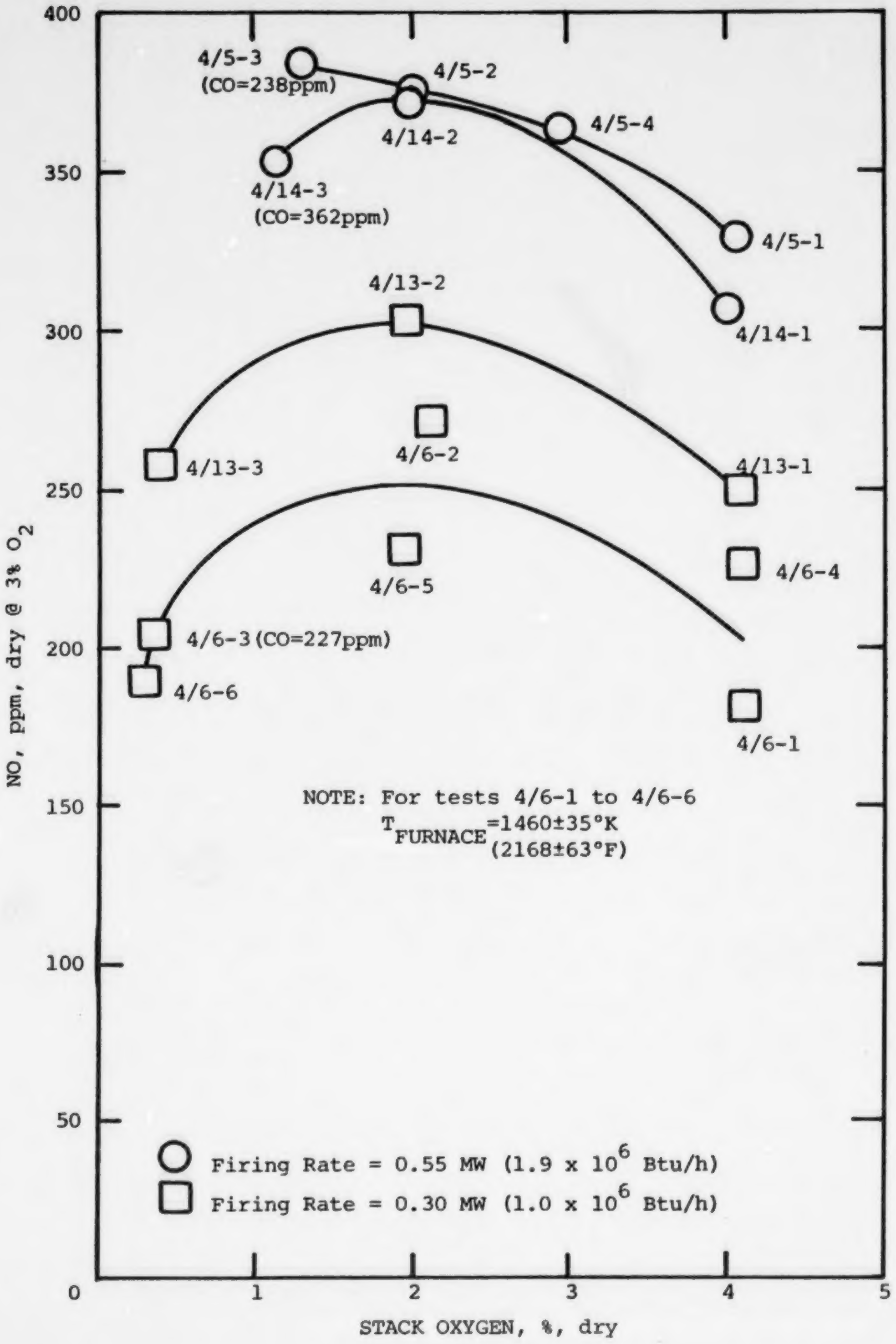


Figure 6-3. NO emission as a function of stack oxygen for a subscale steel furnace firing No. 2 oil.

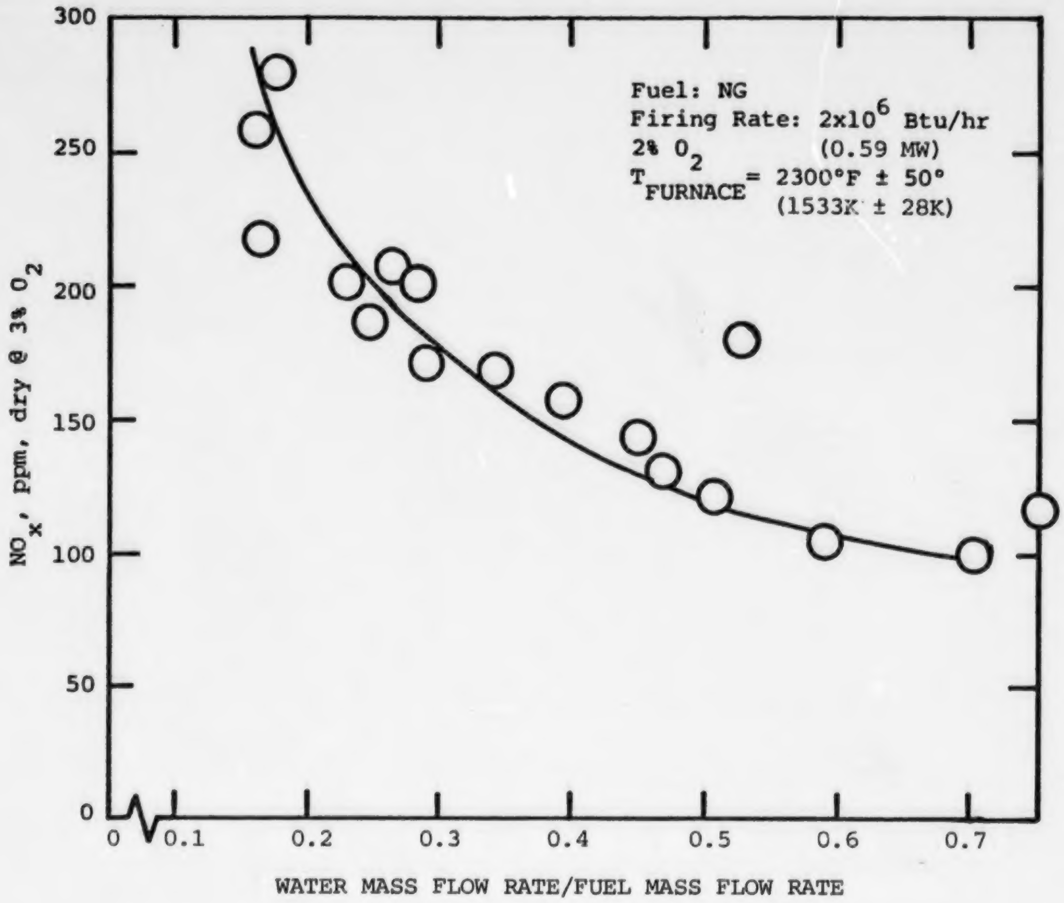


Figure 6-4. NO emission as a function of water injection rate for subscale steel furnace firing natural gas.

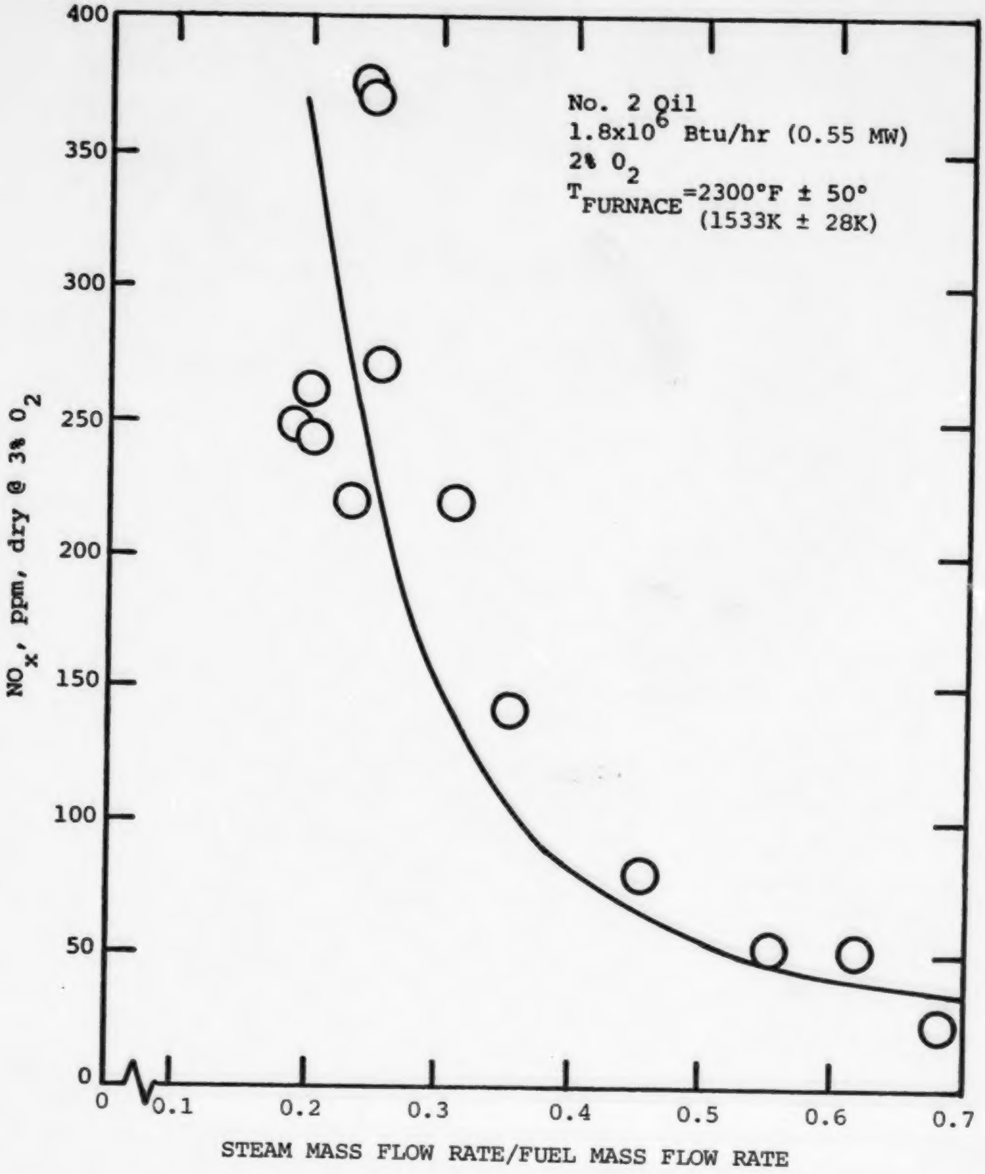


Figure 6-5. NO emission as a function of steam injection rate for a subscale steel furnace firing No. 2 oil.

Figures 6-4 and 6-5 reveal the sensitivity of NO to change in H_2O injection rate, particularly when firing No. 2 oil. The maximum percent NO reduction obtained by injecting water with natural gas was 47 percent as compared with 89 percent reduction of NO obtained by injecting steam with No. 2 oil. It was not practical to try steam injection with natural gas or water injection with No. 2 oil with this particular burner design.

Flue gas recirculation resulted in large NO reductions for both natural gas and No. 2 oil fuels (see Figures 6-6 and 6-7). The greatest decrease in NO using the flue gas recirculation technique was observed when firing natural gas (88 percent reduction).

6.3 COST ANALYSIS OF COMBUSTION MODIFICATIONS

6.3.1 Initial Capital Costs

A. Capital Costs of Steam and Water Injection for Steel Furnaces--

For a plant which has steam generating capability but no steam piping to the furnace to which the steam injection modification is to be applied, the capital costs were determined in Section 4.1. For three heater sizes those costs are shown below in 1980 dollars:

2.9 MW ($10x10^6$ Btu/hr)	73.3 MW ($250x10^6$ Btu/hr)	147 MW ($500x10^6$ Btu/hr)
$3,500	$19,000	$32,000

Although these costs were developed for a process heater modification it is not expected that they will differ substantially for a steel furnace modification. They involve only straightforward piping changes to get the steam from existing headers to the furnace itself.

B. Flue Gas Recirculation Capital Costs for Steel Furnaces--

The capital costs determined for flue gas recirculation systems for process heaters are used here to estimate the costs of a flue gas recirculation system for steel furnaces. There are only two substantial differences between a flue gas recirculation system for a refinery process heater and a steel furnace system:

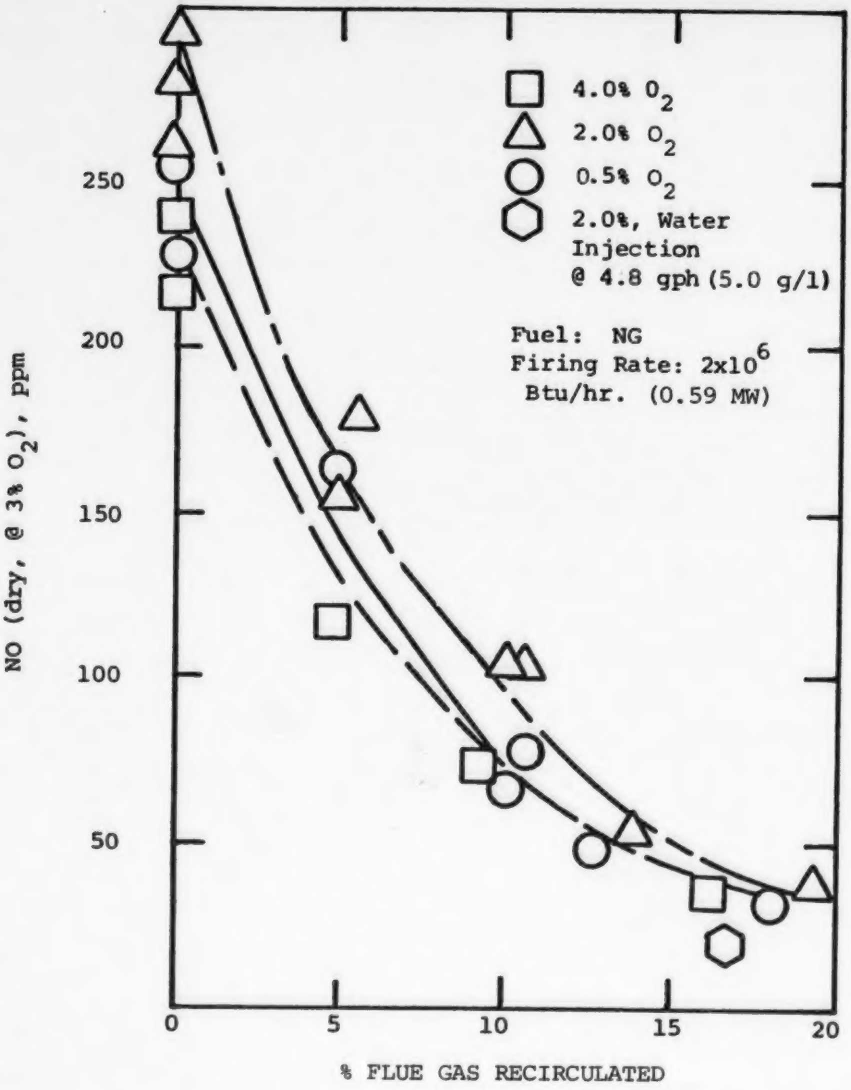


Figure 6-6. NO emission as a function of percent flue gas recirculated for a subscale steel furnace firing natural gas.

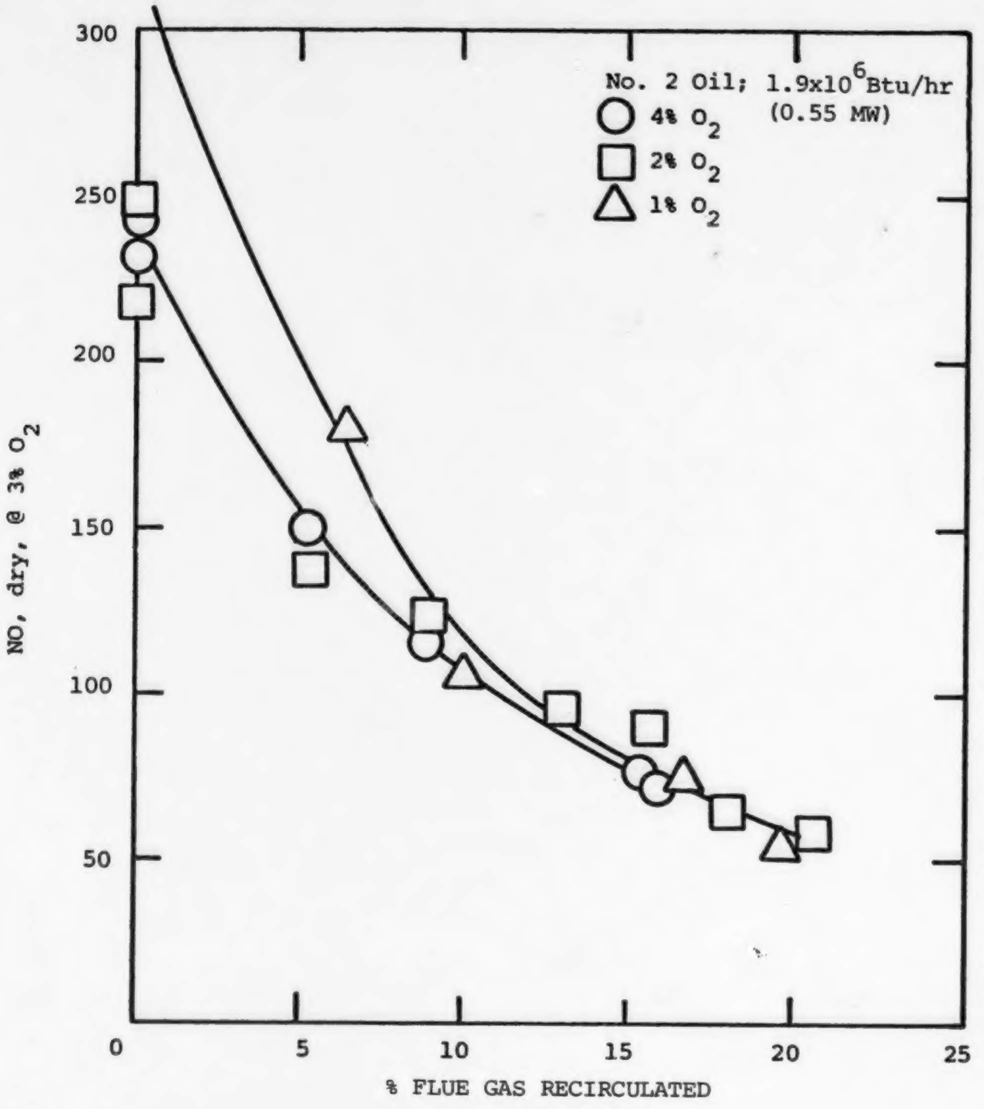


Figure 6-7. NO emission as a function of percent flue gas recirculated for a subscale steel furnace firing No. 2 oil.

1. A heat exchanger may be needed in a steel furnace application in order to cool the flue gases to a temperature which can be sent through the recirculating fan. This heat exchanger could act as regenerator, thereby increasing the efficiency of the unit and offsetting its cost at least in part.

2. A burner plenum would not be required in a forced-draft steel furnace whereas it was required in a natural draft process heater for which there was not existing forced air injection capability.

Although the costs previously developed for flue gas recirculation on a process heater were based on 30% flue gas recirculation, those 1978 costs will probably not differ significantly from the costs of a 20% flue gas recirculation system built in 1980. Thus, for the purposes of the present study, those cost figures will be used without escalation to represent the costs of a 20% flue gas recirculation system installed on a steel furnace. The initial installed costs were shown in Table 4-7.

6.3.2 Annual Operating Costs

A. Annual Operating Costs for Steam and Water Injection in Steel Furnaces--

The total annual steam cost for process heater modification at 0.01 kg/s (75#/hr) = $1,300/burner (mid-1978 $). In that calculation the steam cost varies with the steam injection rate ($\dot{m}$=lb/hr) as follows:

$$\text{Total annual steam cost} = N\dot{m}_{STM}\ (C_1 + C_2 + C_3) \times P.I.$$

where N is the number of burners, P.I. is the price index and C_1, C_2, C_3 are constants relating to 1978 water supply costs, steam generation costs, and water treatment costs, respectively. For an 80% use factor (i.e., assuming an average steam mass flow rate of 80% over a single year) and an 80% efficiency for the conversion of heat input to steam, $C_1 = 0.391$; for NG, $C_2 = 18.501$; for No. 2 oil, $C_2 = 38.263$; for No. 6 oil, $C_2 = 32.797$; and $C_3 = 2.383$. These numbers will give costs in 1978 dollars for a furnace containing N burners. To get 1980 dollars one must multiply by the price index relative to mid-1978. The Chemical Engineering Plant Cost Index (January 14, 1980) is 1.15. This value is used here as a suitable price index.

Thus, for $\dot{m}_{STM}$ in lb/hr,

$$\begin{aligned}\text{Total Annual Steam Cost} &= 21.275 \times \dot{m}_{STM}N && \text{(NG)}\\ &= 41.037 \times \dot{m}_{STM}N && \text{(No. 2)}\\ &= 35.571 \times \dot{m}_{STM}N && \text{(No. 6)}\end{aligned}$$

This relationship is shown in Figure 6-8. These costs do not include maintenance costs since those are expected to be a small fraction of the total annual operating costs. If $\dot{m}_{STM}$ = Kg/s, multiply the above equations by 7936.6.

Similarly, the total annual water cost to calculated below. (Since ordinary domestic water could be used in a water injection system, water treatment costs are not included here.)

$$\text{Total Annual Water Cost} = N\dot{m}_{H_2O} \times C_1 \times \text{P.I.} = 0.450\ N\dot{m}_{H_2O} \qquad (\dot{m}_{H_2O} = \text{lb/hr})$$

These figures do not include maintenance costs. The total actual water cost, including the cost of maintenance, may be somewhat greater than the cost calculated by this equation. To allow for this the values plotted in Figure 6-9 are increased by 20% over the values determined from the above relationship.

Additional annual costs in the form of increased fuel requirements brought about by steam and water injection must also be considered. The additional fuel requirement is calculated in Appendix D for a subscale steel furnace with a maximum firing rate of 0.59 MW (2.0 x 10^6 Btu/hr) and 0.005 Kg/s (40 lb/hr) steam injection. The additional heat required is directly proportional to the steam or water flow rate. The relationship is given below:

$$\Delta h_s = NC_{STM}\ \dot{m}_{STM}$$

$$\Delta h_w = NC_{WATER}\ \dot{m}_{WATER}$$

Where C_{WATER} = 2,387 Btu/lb and C_{STM} = 1275 Btu/lb, N is the number of burners in the furnace, and Δh is the incremental heat input requirement in units of Btu/hr. The cost increase on an annual basis may be determined, assuming an 80% use factor, as follows:

$$\text{Increase in Total Annual Fuel Cost} = \Delta h \times \frac{\text{Cost}}{\text{Unit Heat Input}} \times 8760\ \frac{h}{y} \times 0.80$$

The cost per unit heat input for typical natural gas fuel is \$2.20/10^6 Btu (Ref. 15), the cost for No. 2 oil is \$4.55/10^6 Btu, and the cost of No. 6 oil is \$3.90/10^6 Btu (Ref. 16). The increase in total annual fuel cost is

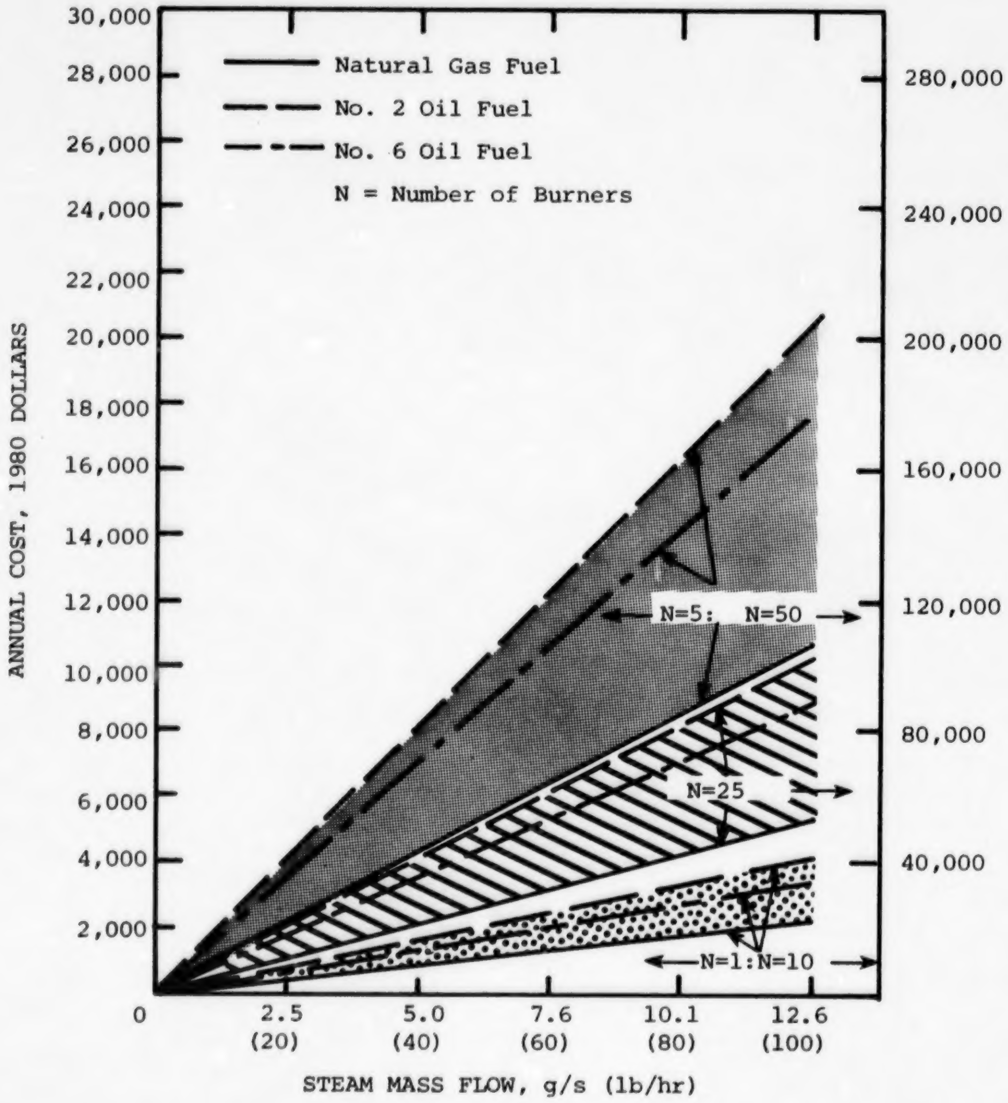


Figure 6-8. Annual steam cost as a function of steam injected per burner for different numbers of burners and different fuels.

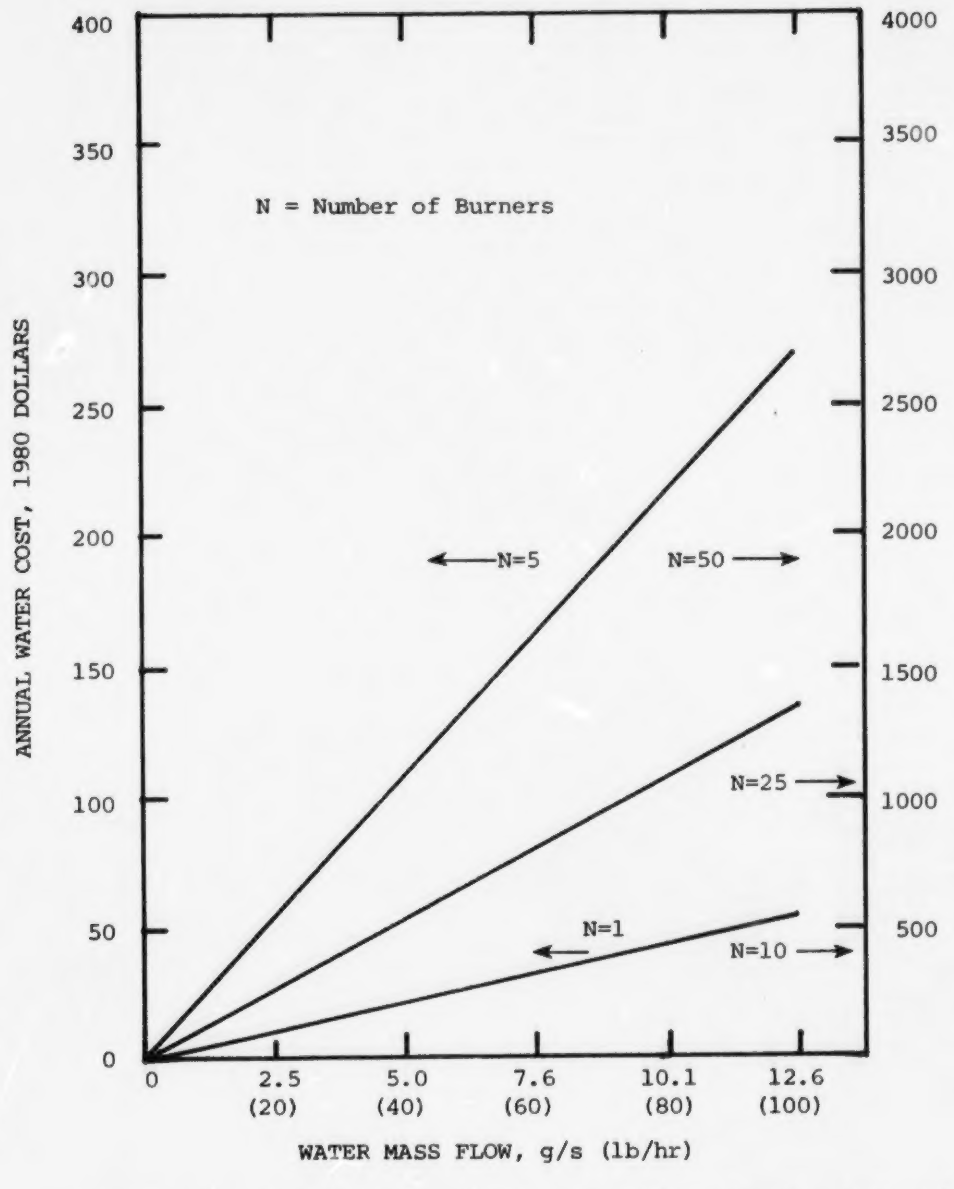


Figure 6-9. Annual water cost as a function of water injected per burner for different numbers of burners, N.

graphed in Figures 6-10, 11, and 12 as a function of steam or water flow rates for different numbers of burners. The calculation of Δh is explained in Appendix D.

The total annual costs of steam and water injection, including water cost, steam generation cost, additional fuel requirement cost, and maintenance, are shown in Table 6-3 for three heater sizes using 0.005 Kg/s/burner (40 lb/hr/burner) injection rate. (In order to use Figures 6-10, 11, and 12 each burner is considered to have an average heat input capability of 2.9 MW (10×10^6 Btu/hr)). One observes that the annual operating costs of steam and water injection are, for all practical purposes, equal. Thus, the average of the total annual costs of steam and water injection is used here for costing both modifications.

B. Flue Gas Recirculation Annual Operating Costs--

1. Electrical Costs--A cost analysis of flue gas recirculation annual operating costs for a process heater was presented in Section 4. The electrical cost of fan operation is one of the chief components of the annual operating costs of a flue gas recirculation system. Incremental fuel costs and maintenance costs make up the bulk of the remaining annual costs. In the special case of steel furnaces, heat exchanger maintenance costs would be added to those used in applications involving process heaters since the flue gases used would be much hotter (1366K or 2000°F). The annual maintenance costs are estimated to be ∿10% of initial fixed capital costs.

The additional fuel costs resulting from the use of flue gas recirculation are determined for 20% flue gas recirculation and 2% O_2 in the stack. Efficiencies calculated here assume that the flue gas temperature change from combustion zone to reinjection point is due solely to heat loss to the external environment; i.e., there is no regenerative capability of the flue gas recirculation system.

The additional fuel costs are directly proportional to the mass flow rate of the recirculated flue gas. The relationship used to calculate those costs is the following:

$$\Delta \text{ Cost} = \Delta h_{FGR} \times 8760 \times 0.8 \times \frac{\text{Cost}}{\text{Unit Heat Input}}$$

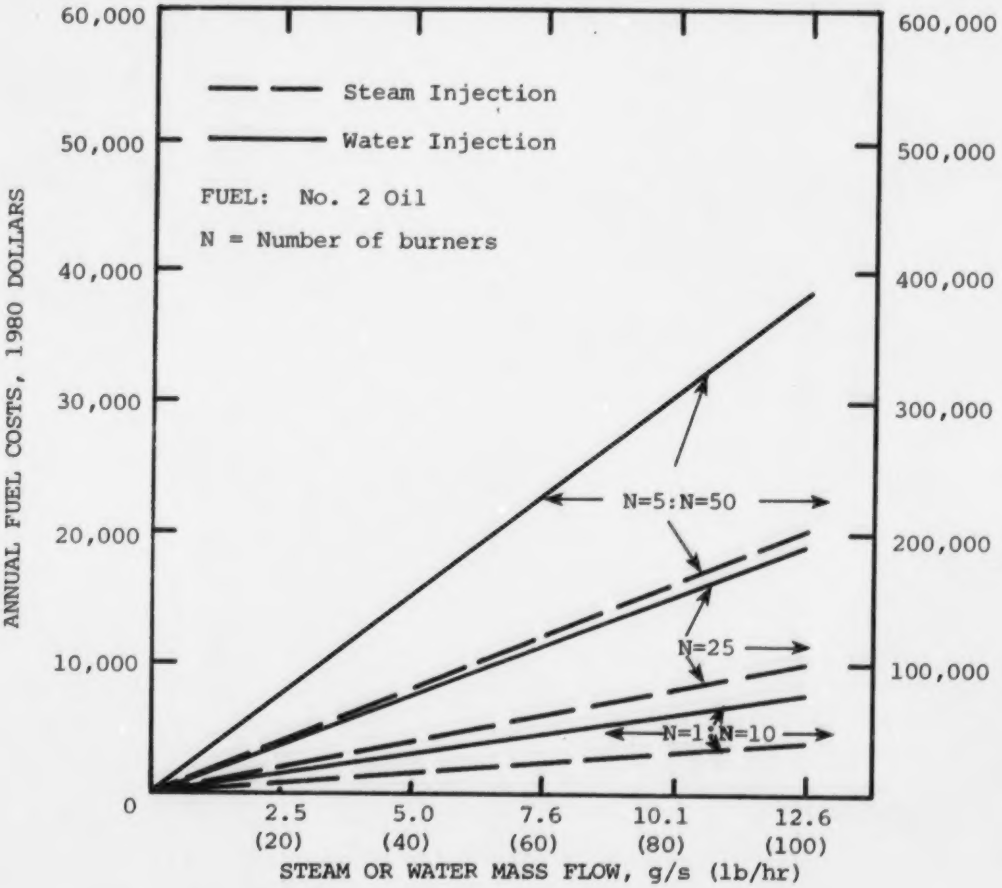


Figure 6-10. Annual additional fuel requirement cost with steam or water in a steel furnace firing No. 2 oil.

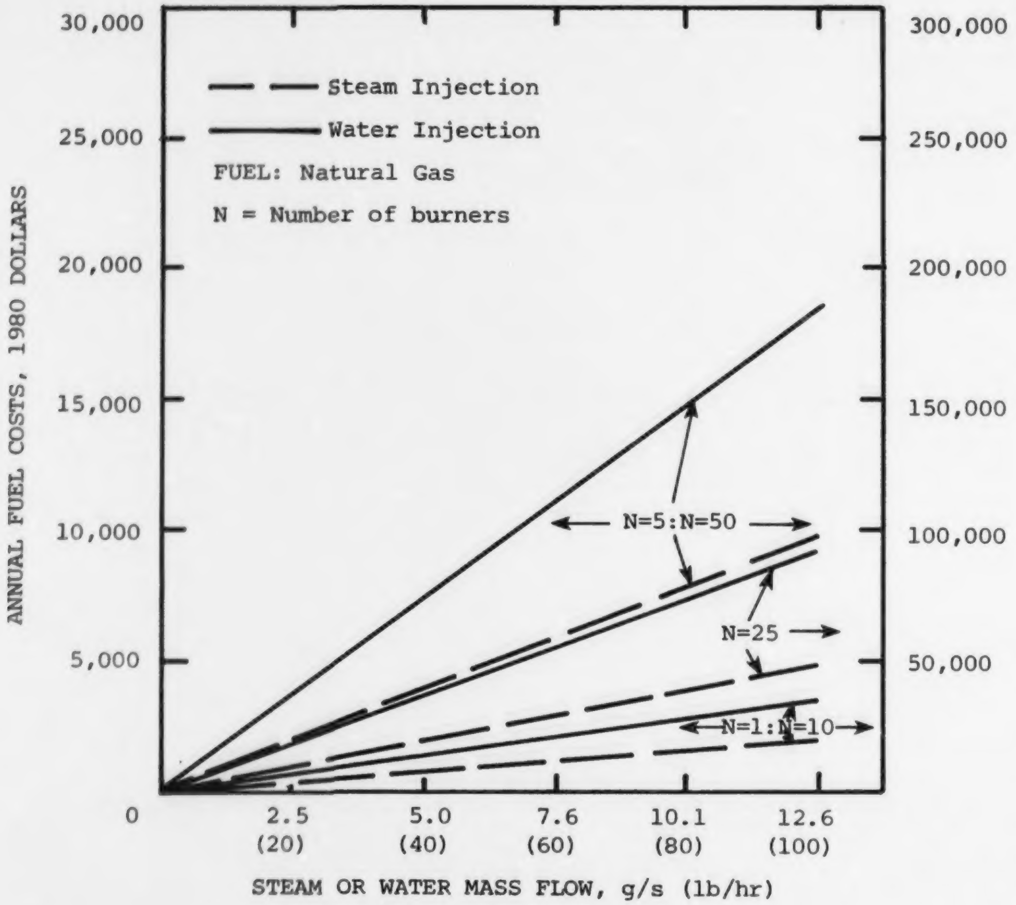


Figure 6-11. Annual additional fuel requirement cost with steam or water injection in a steel furnace firing natural gas.

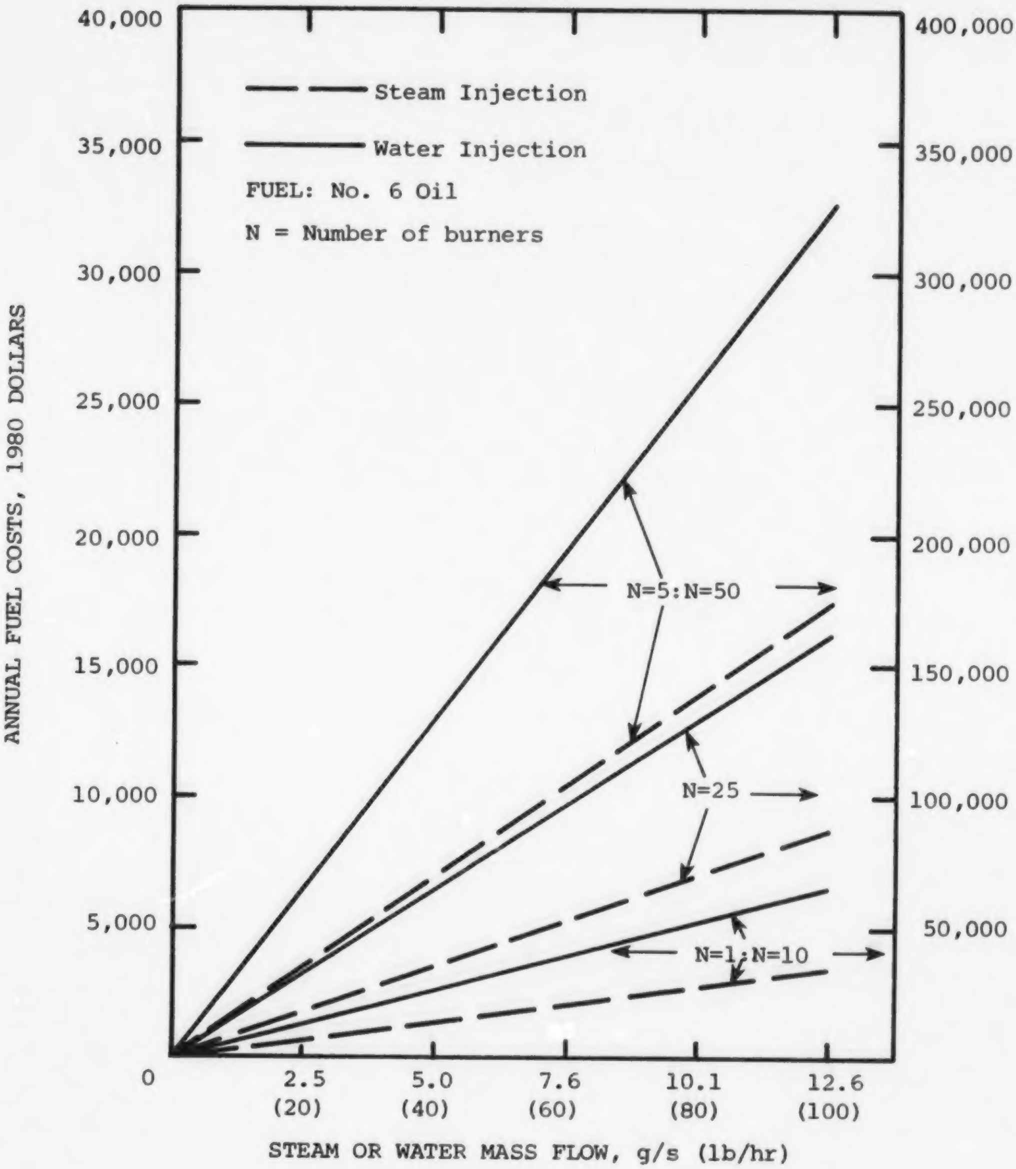


Figure 6-12. Annual additional fuel cost with steam or water injection in a steel furnace firing No. 6 oil.

TABLE 6-3. TOTAL ANNUAL COSTS OF STEAM AND WATER INJECTION

Costs	2.9 MW ($10x10^6$ Btu/hr)		73.3 MW ($250x10^6$ Btu/hr)		147 MW (500×10^6 Btu/hr)	
	No. 2 Oil	NG	No. 2 Oil	NG	No. 2 Oil	NG
Water	$ 22	$ 22	$ 600	$ 600	$ 1,100	$ 1,100
Additional Fuel	3,000	1,400	75,000	37,000	155,000	73,000
Total	$3,022	$1,422	$81,000	$37,600	$156,100	$84,000
Steam	$1,700	$1,000	$41,000	$21,000	$ 83,000	$43,000
Additional Fuel	1,500	750	40,000	20,000	80,000	39,000
Total	$3,200	$1,750	$81,000	$41,000	$163,000	$82,000
Average	$3,100	$1,600	$81,000	$39,300	$159,500	$83,000

Δh_{FGR} is calculated in Appendix D for these typical test conditions: flue gas temperature of 558K (546°F), flue gas density of 0.673 Kg/m^3 (0.042 lbm/ft^3), and specific heat of 1.089 kJ/kg-°C (0.26 Btu/lbm-°F). At these conditions, the above expression may be written in terms of $\dot{m}_{FGR}$ as follows:

$$\Delta \text{ Cost} = 560.04 \times \dot{m}_{FGR} \times 8760 \times 0.8 \times \frac{\text{Cost}}{\text{Unit Heat Input}}$$

where m_{FGR} = lb/hr of flue gas. If the percent FGR and the fuel and combustion and mass flows are known, one can use the following expression to convert percent FGR to $\dot{m}_{FGR}$:

$$\dot{m}_{FGR} = \frac{\text{\% FGR}}{\text{100-\% FGR}} \; (\dot{m}_{FUEL} + \dot{m}_{COMBUSTION\ AIR})$$

At 20% FGR this expression reduces to

$$\dot{m}_{FGR} = 0.25 \; (\dot{m}_{FUEL} + \dot{m}_{COMBUSTION\ AIR})$$

where $\dot{m}_{FUEL}$ and $\dot{m}_{COMBUSTION\ AIR}$ are the mass flows of fuel and combustion air for a given size heater. Using the cost per 10^6 Btu of each of the three fuels--natural gas, No. 2 oil, and No. 6 oil--the incremental annual fuel costs of 20% flue gas recirculation, valid at the flue gas conditions described, are given as follows:

$$\begin{aligned} \Delta\text{Cost} &= 2.159 \; \dot{m}_{FUEL + C.A.} && \text{(Natural Gas)} \\ &= 4.404 \; \dot{m}_{FUEL + C.A.} && \text{(No. 2 Oil)} \\ &= 3.827 \; \dot{m}_{FUEL + C.A.} && \text{(No. 6 Oil)} \end{aligned}$$

Note that 1250 x $\dot{m}_{FUEL + C.A.}$ = Thermal Heat Input (Btu/hr). This is a close approximation for all three fuels and is used in conjunction with the three preceding expressions in developing Figure 6-13.

The cost of electricity to operate the FGR fan may be estimated from the data in Table 4-9. The costs of electricity are graphed as a function of furnace size ($\dot{m}_{FUEL}$ + $\dot{m}_{COMBUSTION\ AIR}$) for 20% flue gas recirculation in Figure 6-14.

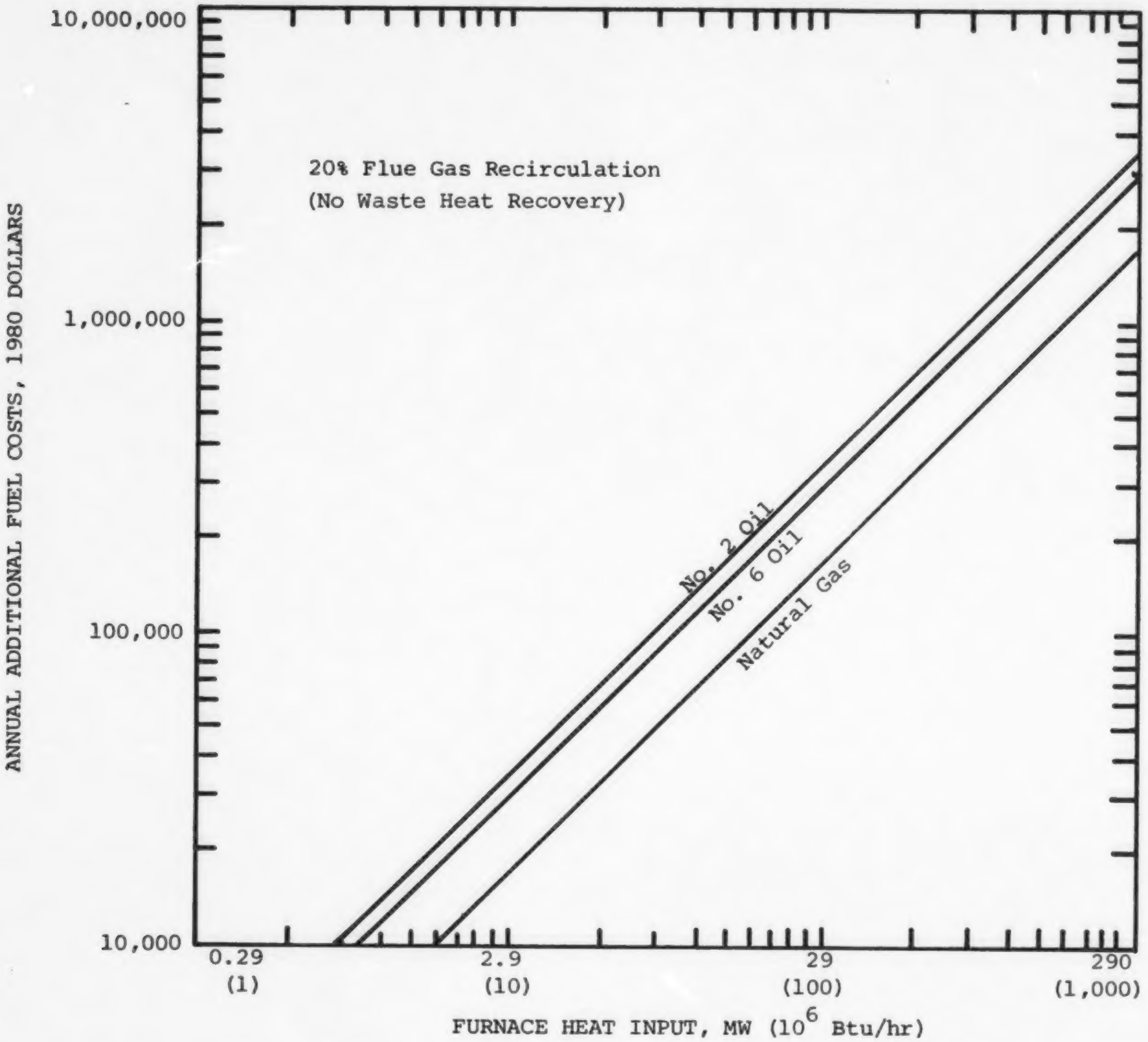


Figure 6-13. Annual additional fuel cost of flue gas recirculation as a function of furnace size in a steel furnace for three different fuels.

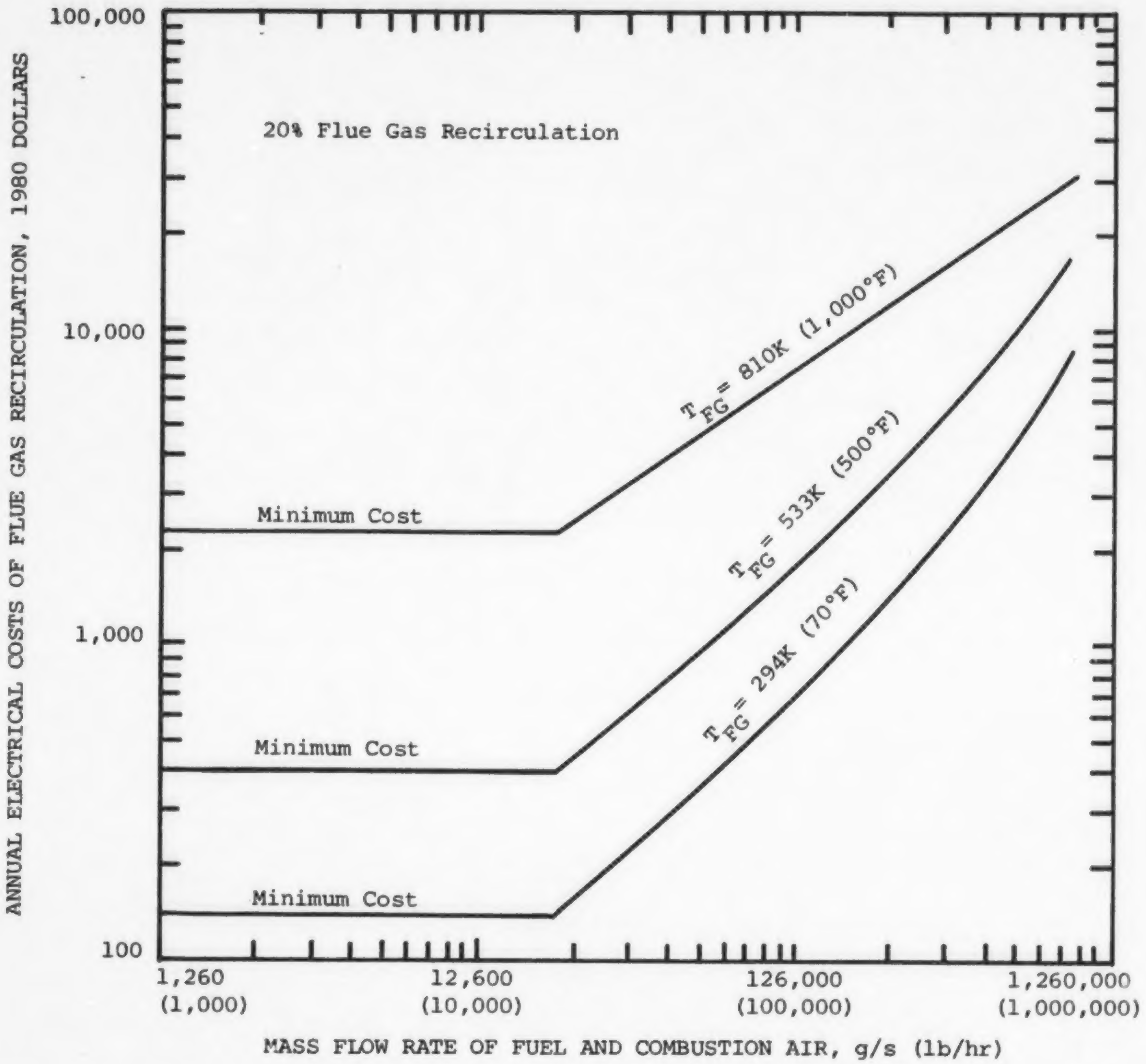


Figure 6-14. Cost of electricity to operate the fan of a FGR system as a function of furnace size and different flue gas temperatures.

TABLE 6-4. ANNUAL OPERATING COSTS OF 20 PERCENT FLUE GAS RECIRCUATION
FOR A STEEL FURNACE FIRING NATURAL GAS OR NO. 2 OIL (1980 DOLLARS)
FLUE GAS TEMPERATURE = 533K (500°F)

Costs	2.9 MW ($10x10^6$ Btu/hr)	733 MW ($250x10^6$ Btu/hr)	147 MW ($500x10^6$ Btu/hr)
Additional Fuel*(NG/No.2)	17,100/35,380	428,000/885,000	856,000/1,770,000
Fan Electricity	400	3,600	7,700
Maintenance	1,850	5,400	9,400
TOTAL (NG/No. 2)	19,350/37,630	437,000/894,000	873,100/1,787,100

* Assuming no waste heat recovery.

The total annual costs (not annualized) taking into account the cost of additional fuel requirements, fan electrical costs, and maintenance cost are given in Table 6-4 for three furnace sizes ($\dot{m}_{FUEL} + \dot{m}_{COMBUSTION\ AIR}$) for natural gas or No. 2 oil firing.

Again, it is emphasized that the incremental fuel costs shown here were determined for the worst case in which nearly all of the sensible heat of the recirculated flue gas is lost to the furnace surroundings. This situation would probably not prevail in a practical, full-size steel furnace. However, it is impossible to predict, at this time, how much heat may be retained in the furnace.

6.3.3 Total Annualized Costs

The initial fixed capital costs of combustion modifications are annualized making the following assumptions:

1. Straight-line depreciation of capital assets over a 12-year life span.
2. After-tax rate of return of 15 percent.
3. State and federal property taxes totalling 11 percent of the initial capital cost.
4. Insurance charges of 0.5% of the initial capital cost.
5. Debt/equity ratio of 0 (100% equity) for financing of initial fixed capital costs.
6. Annual income tax rate (state and federal) of 50 percent.
7. Annual investment tax credit of 10 percent (applies only to the first year of operation).

The annualized capital costs must then be added to the annual operating costs to give the total annualized cost of combustion modifications.

A. Total Annualized Costs of Water or Steam Injection--

The calculation of total annual expenses and total annualized cost of the water or the steam injection modifications to a steel furnace are shown on the next page for No. 2 oil firing and natural gas firing.

TOTAL ANNUALIZED COSTS OF WATER OR STEAM INJECTION

Annual Operating Cost (No. 2/Natural Gas)	$3,100/1,600	$81,000/39,300	$159,500/83,000
State and Federal Taxes (11% of IFC)	385	2,090	3,520
Insurance (0.5% of IFC)	18	95	160
Total Annual Expenses (No. 2)	$3,503	$83,185	$163,180
Total Annual Expenses (Natural Gas)	$2,003	$41,485	$86,680
INITIAL FIXED COSTS (IFC)	3,500	19,000	32,000

(WATER OR STEAM)
ROR=i=15%,n=12
Capital Recovery Factor=.1845=CR
Annual Income Tax Rate=50%
Investment Tax Credit=10%=i_c (1st year only)

Total Annual Capital Factor* (ACF)=.2773

Annual Capital Charge (=IFCxACF)	971	5,269	8,875
TOTAL ANNUALIZED COSTS (1980 DOLLARS)			
No. 2 Oil	4,474	88,454	172,055
Natural Gas	2,974	46,754	95,555

$$*ACF = CR + T\left(CR - \frac{1}{n}\right) - \frac{i_c}{n}$$

where CR = capital recovery factor = $\frac{i}{1-(1+i)^{-n}}$

and T = 1.0 (for debt/equity ratio of 0)

B. Total Annualized Costs of Flue Gas Recirculation--

The total annual expenses and total annualized costs of flue gas recirculation on a steel furnace are determined below for No. 2 oil-firing and natural gas firing.

TOTAL ANNUALIZED COSTS OF FGR

Annual Operating Costs (No. 2/Natural Gas)	37,630/19,350	894,000/437,000	1,787,100/873,100
State and Federal Taxes (11% of IFC)	2,035	5,940	10,340
Insurance (0.5% of IFC)	100	270	470
Total Annual Expenses (No. 2)	$39,765	$900,210	$1,797,910
Total Annual Expenses (Natural Gas)	$21,485	$443,210	$883,910
INITIAL FIXED COSTS ROR=i=15%,n=12 Capital Recovery Factor=.1845 Annual Income Tax Rate=t=50% Investment Tax Credit=i_c=10% (1st year only)	18,500	54,000	94,000
Total Annual Capital Factor =.2773			
Annual Capital Charge	5,131	14,976	26,069
TOTAL ANNUALIZED COSTS (1980 DOLLARS)			
No. 2 Oil	44,896	915,186	1,823,979
Natural Gas	26,616	458,186	909,979

6.3.4 Cost Effectiveness

The cost effectiveness of a combustion modification is defined as the total annualized cost of the modification divided by the annual NO_x emission reduction potential of the modification (in thousands of Kg). The annual NO_x emission reduction potential for steam and water injection and for flue gas recirculation firing No. 2 oil and natural gas is given in Table 6-5. The equation at the bottom of the table was derived from the expression used in Section 4, page 4-73 for NO_x reduction potential from process heaters.

The cost effectiveness of steel furnace combustion modifications for two different fuels and three furnace sizes including the annual incremental fuel costs is given in Table 6-6.

It is important to note that while the steel furnace cost effectiveness values include annual fuel costs due to combustion modification, those values calculated for the cost effectiveness of combustion modifications made on a process heater do not. The annual fuel cost turns out to be the most significant item in the cost effectiveness calculation for steel furnaces. These costs were calculated for steel furnaces based on the annual incremental fuel requirements of combustion modifications. Certain assumptions were made in the calculation of those fuel requirements. They are explained along with those calculations in Appendix D.

It was felt that similar incremental fuel calculations would not be meaningful for process heaters because data concerning the effects of combustion modifications on heater efficiency were inconclusive.

It should be observed that the calculation of the annual incremental fuel cost of flue gas recirculation in steel furnaces is a worst-case calculation. This is so because one of the assumptions made in the calculation is that all of the heat of the recirculated flue gas is lost to the surroundings between the point of extraction near the flame zone and the point of reinjection into the furnace. Most likely, in a practical application, some of that heat would be used to preheat combustion air or in some other waste heat recovery scheme. Thus, fuel costs of flue gas recirculation would probably be considerably less than reported here.

TABLE 6-5. PROJECTED BASELINE NO_x EMISSIONS FROM STEEL FURNACES

Modification	Fuel	Heat Input MW	NO Concentration ng/J	Annual Emission 10^3Kg NO	Reduction Percent	Annual Reduction 10^3 Kg NO
Steam	No.2	2.93	153.4	11.3	89	10.1
Steam	No.2	73.2	153.4	283	89	252
Steam	No.2	147	153.4	568	89	506
Water	NG	2.93	114.6	8.5	47	4.0
Water	NG	73.2	114.6	211	47	99
Water	NG	147	114.6	425	47	200
FGR	No.2	2.93	153.4	11.3	77	8.7
FGR	No.2	73.2	153.4	283	77	218
FGR	No.2	147	153.4	568	77	437
FGR	NG	2.93	114.6	8.5	88	7.5
FGR	NG	73.2	114.6	211	88	186
FGR	NG	147	114.6	425	88	374

$$\text{Annual } NO_x \text{ Emission} \equiv \frac{10^3 \text{ Kg NO}}{y} = 0.0252 \times \text{MW} \times \frac{ng}{J}$$

TABLE 6-6. COST EFFECTIVENESS OF COMBUSTION MODIFICATIONS ON A STEEL FURNACE ($/Mg OF NO_x REDUCTION) INCLUDING ANNUAL INCREMENTAL FUEL COSTS

	Furnace Heat Input		
Modification	2.9 MW (10×10^6 Btu/hr)	73.3 MW (250×10^6 Btu/hr)	147 MW (500×10^6 Btu/hr)
STEAM INJECTION			
No. 2 Oil	443	351	340
NG	294	186	189
WATER INJECTION			
No. 2 Oil	1,119	893	860
NG	744	472	478
FLUE GAS RECIRCULATION			
No. 2 Oil	5,160	4,198	4,174
NG	3,549	2,463	2,433

6.3.5 Cost Calculations for Flue Gas Recirculation Applied to Steel Furnaces - Case II

If complete recovery of the flue gas energy in the recirculated flue gas may be assumed such that the only losses in the steel furnace system are the stack losses, then there will be no fuel penalty associated with the flue gas recirculation modification. In this instance, the annual operating costs of 20% flue gas recirculation in a steel furnace will consist of only the fan electrical and system maintenance cost elements. The annual operating costs for three heater sizes assuming full recovery of the heat of the recirculated flue gas is shown in Table 6-7.

TABLE 6-7. ANNUAL OPERATING COSTS FOR A STEEL FURNACE HAVING 20% FLUE GAS RECIRCULATION (1980 $)

Heater Size	2.9 MW	73.3 MW	147 MW
Fan Electricity	$ 400	$3,600	$7,700
Maintenance	1,850	5,400	9,400
Total	$2,250	$9,000	$17,100

The revised total annualized costs of flue gas recirculation on steel furnaces are shown in Table 6-8.

TABLE 6-8. TOTAL ANNUALIZED COSTS OF 20% FLUE GAS RECIRCULATION ON A STEEL FURNACE WITH WASTE HEAT RECOVERY (1980 $)

2.9 MW	73.3 MW	147 MW
$9,516	$30,186	$53,979

The annual NO_x reduction capability of the flue gas recirculation modification and the cost effectiveness (equal to the total annualized cost divided by the annual NO_x reduction) are given in Table 6-9.

TABLE 6-9. ANNUAL NO_x EMISSION REDUCTION AND COST EFFECTIVENESS OF FLUE GAS RECIRCULATION (1980 $)

Heater Size	2.9 MW		73.3 MW		147 MW	
	No. 2 Oil	NG	No. 2 Oil	NG	No. 2 Oil	NG
Annual NO_x Emission Reduction Capability (Mg/y)	8.7	7.5	218	186	437	374
Cost Effectiveness ($/Mg)	1094	1269	138	162	124	144

Note that if the assumption of total waste heat recovery from the recirculated flue gas is valid (as could be the case if the flue gas for flue gas recirculation comes from the outlet of a waste heat boiler or a regenerative heat exchanger), then flue gas recirculation becomes more attractive than either steam or water injection modifications for larger heater sizes (73.3 MW and up). For small heaters, however, it is not as cost effective as steam injection with either No. 2 oil or natural gas fuels nor is it as cost effective as water injection firing natural gas.

The cost effectiveness of flue gas recirculation with full heat recovery may be compared to the cost effectiveness calculations in Table 6-6.

The cost effectiveness values in Table 6-6 and Table 6-9 are plotted in Figure 6-15 against heater size for No. 2 oil fuel. It can be seen that flue gas recirculation with heat recovery capability has the lowest cost per Mg NO_x reduction for heaters larger than 13.5 MW (46 x 10^6 Btu/h). For natural gas fuel, flue gas recirculation with heat recovery becomes cheaper than water injection for heater sizes greater than 8.5 MW (29 x 10^6 Btu/h) and it is cheaper than steam injection at heater sizes in excess of 60 MW (205 x 10^6 Btu/h) as shown in Figure 6-16.

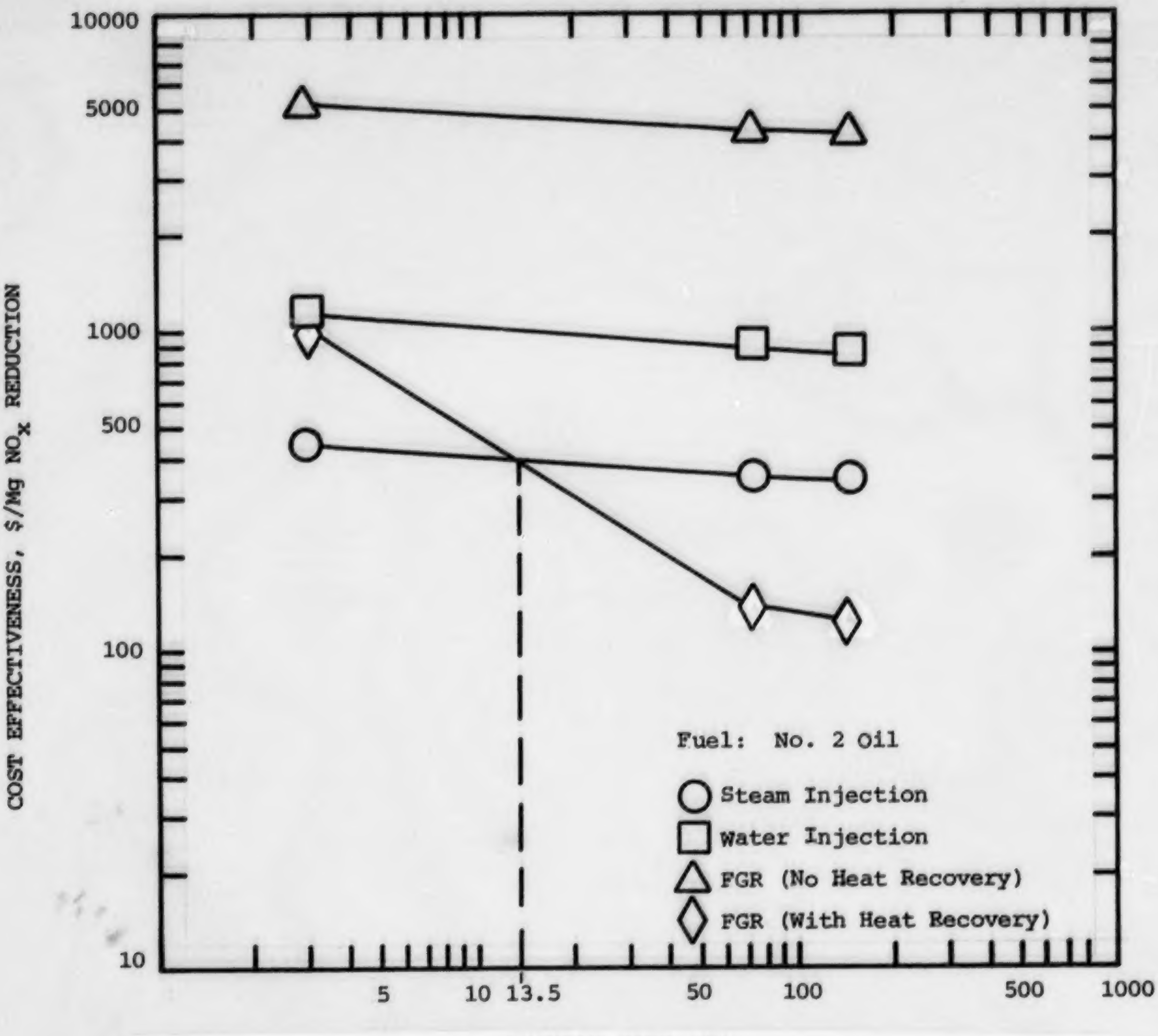


Figure 6-15. Cost effectiveness as a function of furnace size for No. 2 oil fuel.

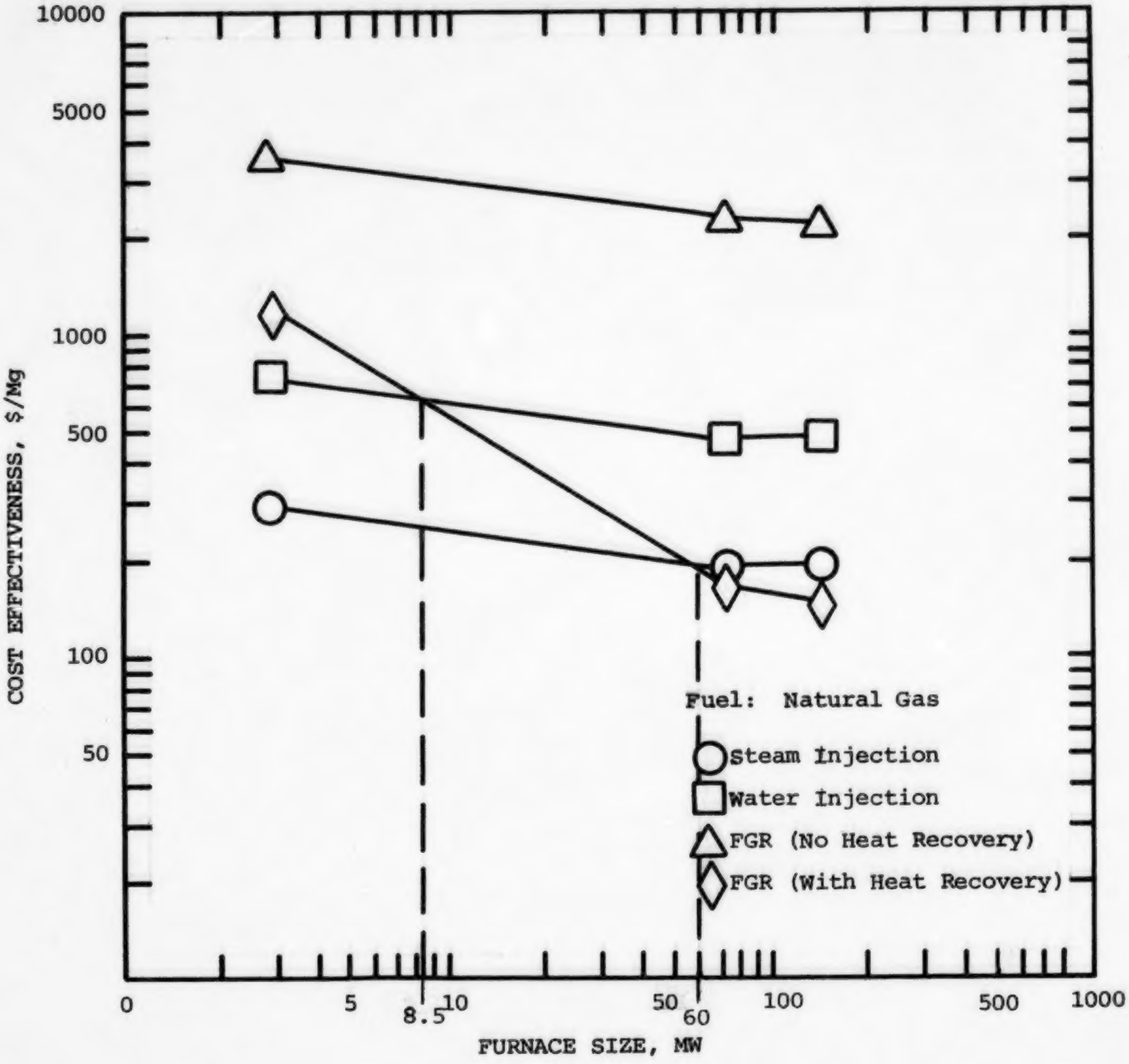


Figure 6-16. Cost effectiveness as a function of furnace size for natural gas fuel.

6.4 CONCLUSIONS

The results of the tests at the subscale steel furnace are summarized below:

1. Large NO emission reductions were obtained when firing natural gas and No. 2 oil by the method of H_2O injection and by the flue gas recirculation technique.

2. Excess air variations did not affect NO emissions significantly except at a high O_2 level, which is a less efficient mode of operation.

3. From the standpoint of NO reduction capability, without regard to efficiency considerations, the steam injection technique appeared to give the best results when firing No. 2 oil, and FGR gave the best results when firing natural gas.

4. Measured flame temperature profiles indicate that NO increases directly with the temperature in the flame zone; average flame zone temperatures ranged from 1367 to 1922K (2000 to 3000°F).

5. Final calculations of the relative cost of combustion modifications indicate that steam or water injection offers the best NO removal capability for the least cost.

SECTION 7.0

REFERENCES

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SECTION 8.0

CONVERSION FACTORS

SI Units to Metric or English Units

To Obtain	From	Multiply By
g/Mcal	ng/J	0.004186
10^6 Btu	GJ	0.948
Btu	gm cal	3.9685×10^{-3}
lb/10^6 Btu	ng/J	0.00233
ft	m	3.281
in.	cm	0.3937
ft^2	m^2	10.764
ft^3	m^3	35.314
lb	kg	2.205
Fahrenheit	Celsius	$t_F = 9/5(t_c) + 32$
Fahrenheit	Kelvin	$t_F = 1.8t_K - 460$
psig	Pa	$P_{psig} = (P_{pa})(1.450 \times 10^{-4}) - 14.7$
psia	Pa	$P_{psia} = (P_{pa})(1.450 \times 10^{-4})$
iwg (39.2 °F)	Pa	$P_{iwg} = (P_{pa})(4.014 \times 10^{-3})$
10^6 Btu/hr	MW	3.413
GJ/hr	MW	3.60

To Obtain ppm at 3% O_2 of	Multiply* Concentration in ng/J by
Natural Gas Fuel	
CO	3.23
HC	5.65
NO or NO_x	1.96
SO_2 or SO_x	1.41
Oil Fuel	
CO	2.93
HC	5.13
NO or NO_x	1.78
SO_2 or SO_x	1.28
Coal Fuel	
CO	2.69
HC	4.69
NO or NO_x	1.64
SO_2 or SO_x	1.18

*These conversions depend on fuel composition. The values given are for typical fuels.

English and Metric Units to SI Units

To Obtain	From	Multiply By
ng/J	$lb/10^6$ Btu	430
ng/J	g/Mcal	239
GJ	10^6 Btu	1.055
m	ft	0.3048
cm	in.	2.54
m^2	ft^2	0.0929
m^3	ft^3	0.02832
kg	lb	0.4536
Celsius	Fahrenheit	$t_c = 5/9\ (t_F - 32)$
Kelvin	Fahrenheit	$t_K = 5/9\ (t_F - 32) + 273$
Pa	psig	$P_{pa} = (P_{psig} + 14.7)(6.895x10^3)$
Pa	psia	$P_{pa} = (P_{psia})(6.895x10^3)$
Pa	iwg (39.2 °F)	$P_{pa} = (P_{iwg})(249.1)$
MW	10^6 Btu/hr	0.293
MW	GJ/hr	0.278

To Obtain ng/J of	Multiply* Concentration in ppm @ 3% O_2 by
Natural Gas Fuel	
CO	0.310
HC	0.177
NO or NO_x (as NO_2)	0.510
SO_2 or SO_x	0.709
Oil Fuel	
CO	0.341
HC	0.195
NO or NO_x (as NO_2)	0.561
SO_2 or SO_x	0.780
Coal Fuel	
CO	0.372
HC	0.213
NO or NO_x (as NO_2)	0.611
SO_2 or SO_x	0.850

*These conversions depend on fuel composition. The values given are for typical fuels.

APPENDIX A

SUMMARY OF GASEOUS EMISSION DATA, LOCATION 1, PROCESS HEATER RESEARCH FURNACE

APPENDIX A

TABLE A-1. SUMMARY OF GASEOUS EMISSION DATA, LOCATION 1, PROCESS HEATER RESEARCH FURNACE

Test No.	Fuel	Date, 1978	Heat Input Rate MW	Heat Input Rate (10^6Btu/h)	O_2, %	CO_2, %	NO_x ppm*	NO_x ng/J	NO ppm*	NO ng/J	CO ppm*	SO_2 ppm*	Stack Temp. K	Stack Temp. (°F)	Heater Effi-ciency %	Smoke Spot	ϕ_B	Staging Height m	Staging Height (ft)	FGR %	Comments
1/1-1	NG	1/12	1.49	(5.1)	2.8	11.0	114	58	107	55	0	0	1167	(1641)	49.3	--	--	--	--	--	Baseline, MA-16 Brn Pattern II
1/1-2	NG	1/13	1.49	(5.1)	3.9	10.2	111	57	104	53	0	0	1115	(1547)	49.6	--	--	--	--	--	O_2 swing, MA-16 Brn Pattern II
1/1-3	NG	1/13	1.49	(5.1)	2.9	10.9	108	55	104	63	0	0	1125	(1567)	50.7	--	--	--	--	--	O_2 swing, MA-16 Brn Pattern II
1/1-4	NG	1/13	1.49	(5.1)	2.1	10.9	105	54	104	53	0	0	1142	(1596)	51.5	--	--	--	--	--	O_2 swing, MA-16 Brn Pattern II
1/1-5	NG	1/13	1.49	(5.1)	1.1	12.8	93	47	89	45	0	0	1166	(1640)	51.6	--	--	--	--	--	O_2 swing, MA-16 Brn Pattern II
1/1-6	NG	1/13	1.49	(5.1)	0.3	12.0	83	42	82	42	139	0	1179	(1662)	52.2	--	--	--	--	--	O_2 swing, MA-16 Brn Pattern II
1/1-7	NG	1/13	1.49	(5.1)	3.7	11.0	118	60	115	59	0	0	1183	(1669)	46.8	--	--	--	--	--	O_2 swing, MA-16 Brn Pattern II
1/1-8	NG	1/13	1.49	(5.1)	3.0	11.0	113	58	111	57	0	0	1185	(1674)	47.5	--	--	--	--	--	O_2 swing, MA-16 Brn Pattern II
1/1-9	NG	1/16	1.49	(5.1)	3.5	10.3	118	60	115	59	0	0	1099	(1518)	51.0	--	--	--	--	--	Baseline, MA-16 Brn Pattern IV
1/1-10	NG	1/16	1.49	(5.1)	3.1	10.8	120	61	117	60	0	0	1163	(1634)	48.6	--	--	--	--	--	Baseline, MA-16 Brn Pattern II Modified
1/1-11	No.6	1/17	1.38	(4.7)	3.2	13.1	321	180	313	176	0	1354	1093	(1507)	55.7	3	--	--	--	--	Baseline, MA-16 Brn Tip 764
1/1-12	No.6	1/18	1.40	(4.8)	3.0	13.8	311	174	305	171	0	1310	1042	(1416)	58.3	3	--	--	--	--	O_2 swing, MA-16 Brn Tip 764
1/1-13	No.6	1/18	1.37	(4.7)	2.0	14.2	312	175	301	169	0	1467	1069	(1464)	58.6	4	--	--	--	--	O_2 swing, MA-16 Brn Tip 764
1/1-14	No.6	1/18	1.35	(4.6)	1.1	14.4	297	167	282	158	0	1352	1089	(1500)	59.0	5	--	--	--	--	O_2 swing, MA-16 Brn Tip 764
1/1-15	No.6	1/18	1.38	(4.7)	0.8	15.2	284	159	284	159	706	1796	1096	(1513)	59.1	7	--	--	--	--	O_2 swing, MA-16 Brn Tip 764
1/1-16	No.6	1/18	1.37	(4.7)	3.9	13.5	306	172	305	171	0	1284	1108	(1535)	54.0	2.5	--	--	--	--	O_2 swing, MA-16 Brn Tip 764
1/1-17	No.6	1/18	1.39	(4.8)	0.7	15.2	280	157	270	151	17-266	1669	1115	(1548)	58.4	6	--	--	--	--	O_2 swing, MA-16 Brn Tip 764
1/1-18	No.6	1/18	1.36	(4.6)	3.0	13.8	285	160	280	157	0	1431	1135	(1584)	54.1	2	--	--	--	--	Baseline, MA-16 Brn Tip 763
1/1-19	No.6	1/19	1.43	(4.9)	3.0	11.7	284	159	274	154	0	1258	1000	(1340)	59.2	2	--	--	--	--	Baseline, MA-16 Brn Tip 763
1/1-20	No.6	1/19	1.35	(4.6)	3.2	13.3	284	159	277	155	0	1490	1059	(1447)	57.2	2	--	--	--	--	O_2 swing, MA-16 Brn Tip 763

*Corrected to 3% O_2, Dry

(continued)

TABLE A-1 (Continued).

Test No.	Fuel	Date, 1978	Heat Input Rate		O_2, %	CO_2, %	NO_x		NO		CO	SO_2	Stack Temp.		Heater Effi-ciency	Smoke Spot	ϕ_B	Staging Height		FGR	Comments
			MW	(10^6Btu/h)			ppm*	ng/J	ppm*	ng/J	ppm*	ppm*	K	(°F)	%			m	(ft)	%	
1/1-21	No.6	1/19	1.46	(5.0)	3.5	13.3	282	158	276	155	0	1417	1081	(1486)	55.0	2	--	--	--	--	O_2 swing, MA-16, Tip 763
1/1-22	No.6	1/19	1.44	(4.9)	0.9	14.8	229	128	222	125	18	1386	1095	(1512)	58.3	4	--	--	--	--	O_2 swing, MA-16, Tip 763
1/1-23	No.6	1/19	1.38	(4.7)	2.2	13.8	273	153	268	150	0	1354	1107	(1533)	55.8	2	--	--	--	--	O_2 swing, MA-16, Tip 763
1/1-24	No.6	1/19	1.45	(4.9)	3.8	13.6	289	162	283	159	0	1274	1111	(1541)	53.0	2	--	--	--	--	O_2 swing, MA-16, Tip 763
1/1-25	No.2	1/20	1.41	(4.8)	3.1	12.7	112	63	108	61	0	46	958	(1264)	61.4	0	--	--	--	--	Baseline, MA-16 Brn Tip 764
1/2-1	NG	2/13	1.43	(4.9)	2.8	10.6	129	65.8	126	64.3	0	0	998	(1336)	55.5	0	--	--	--	--	Baseline, Low-NO_x (Recirc. Tile) Brn - Pattern III, (Gas tips flush with top of Piece A of burner tile)
1/2-2	NG	2/13	1.43	(4.9)	2.9	11.2	146	74.5	141	71.9	0	0	1071	(1468)	52.3	0	--	--	--	--	Baseline, Low-NO_x (Recirc. Tile) Brn - Pattern III (Gas tips 1/2" below top of piece A of burner tile)
1/2-3	No.2	2/14	1.49	(5.1)	3.9	12.6	110	61.7	105	58.9	0	38	1122	(1560)	52.9	1.5	--	--	--	--	Baseline, Low-NO_x (Recirc. Tile) Brn - Tip 766
1/2-4	No.2	2/14	1.43	(4.9)	1.4	14.4	98	55.0	96	53.9	0	--	1130	(1574)	56.3	1	--	--	--	--	O_2 swing, Low-NO_x (Recirc. Tile) Brn - Tip 766
1/2-5	No.2	2/14	1.35	(4.6)	0.5	14.4	100	56.1	96	53.9	147	--	1124	(1564)	57.4	2	--	--	--	--	O_2 swing, Low-NO_x (Recirc. Tile) Brn - Tip 766
1/2-6	No.2	2/14	1.32	(4.5)	5.1	12.0	119	66.8	109	61.2	0	--	1119	(1555)	49.8	0	--	--	--	--	O_2 swing, Low-NO_x (Recirc. Tile) Brn - Tip 766
1/2-7	No.2	2/14	0.94	(3.2)	5.7	11.9	85	47.7	83	46.6	0	112	1071	(1467)	49.4	4	--	--	--	--	50% Capacity, Low NO_x (Recirc. Tile) Burner, Tip 766
1/2-8	NG	2/15	1.47	(5.0)	3.1	9.9	104	53.0	104	53.0	0	0	1104	(1528)	50.6	0	--	--	--	--	Baseline, Recirc. Tile Burner, Pattern I
1/2-9	NG	2/15	1.47	(5.0)	1.3	10.6	100	51.0	88	44.9	0	0	1153	(1616)	51.4	0	--	--	--	--	O_2 swing, Recirc. Tile Burner, Pattern I
1/2-10	NG	2/15	1.47	(5.0)	0.6	12.0	83	42.3	78	39.8	44	0	1160	(1629)	51.8	0	--	--	--	--	O_2 swing, Recirc. Tile Burner, Pattern I

*Corrected to 3% O_2, Dry

(continued)

TABLE A-1 (Continued).

Test No.	Fuel	Date, 1978	Heat Input Rate		O_2, %	CO_2, %	NO_x		NO		CO	SO_2	Stack Temp.		Heater Efficiency %	Smoke Spot	ϕ_B	Staging Height		FGR %	Comments
			MW	(10^6Btu/h)			ppm*	ng/J	ppm*	ng/J	ppm*	ppm*	K	(°F)				m	(ft)		
1/2-11	NG	2/15	1.49	(5.1)	4.4	10.0	109	55.6	109	55.6	0	0	1159	(1626)	46.0	0	--	--	--	--	O_2 swing, Recirc. Tile Burner, Pattern I
1/2-12	NG	2/15	1.52	(5.2)	2.8	10.6	115	58.7	106	54.1	0	0	1163	(1633)	48.6	0	--	--	--	--	Firing Rate Swing, Recirc. Tile Burner, Pattern I
1/2-13	NG	2/15	1.90	(6.5)	2.9	10.4	114	58.1	113	57.6	0	0	1191	(1684)	48.2	0	--	--	--	--	Firing Rate Swing, Recirc. Tile Burner, Pattern I
1/2-14	NG	2/15	0.94	(3.2)	3.5	10.4	115	58.7	112	57.1	0	0	1122	(1559)	47.1	0	--	--	--	--	Firing Rate Swing, Recirc. Tile Burner, Pattern I
1/2-15	NG	2/15	0.52	(1.8)	8.9	6.8	110	56.1	110	56.1	0	0	1053	(1436)	33.3	0	--	--	--	--	Firing Rate Swing, Recirc. Tile Burner, Pattern I
1/3-1	NG	2/16	0.85	(2.9)	11.2	5.7	89	45.4	87	44.4	0	0	748	(886)	51.2	0	--	--	--	--	Heat-up, Low-NO_x (Tertiary Air) Brn, Pattern IIB (ports at 15° and 45° off radial)
1/3-2	No.6	2/17	1.43	(4.9)	3.2	13.8	260	146	256	144	0	1265	1111	(1539)	54.1	4	--	--	--	--	Baseline, Low-NO_x (Tertiary Air) Brn, Tip 864
1/3-3	No.6	2/17	1.47	(5.0)	3.1	13.6	272	153	266	149	0	1468	1171	(1647)	51.6	1	--	--	--	--	O_2 swing, Low-NO_x (Tertiary Air) Brn, Tip 864
1/3-4	No.6	2/17	1.47	(5.0)	0.5	15.3	235	132	223	125	57	1447	1178	(1661)	55.5	2.5	--	--	--	--	O_2 swing, Low-NO_x (Tertiary Air) Brn, Tip 864
1/3-5	No.6	2/17	1.38	(4.7)	1.4	14.4	248	139	248	139	0	1519	1168	(1643)	54.3	2	--	--	--	--	O_2 swing, Low-NO_x (Tertiary Air) Brn, Tip 864
1/3-6	No.6	2/17	1.38	(4.7)	4.2	13.2	274	154	273	153	0	1391	1168	(1542)	49.5	0.5	--	--	--	--	O_2 swing, Low-NO_x (Tertiary Air) Brn, Tip 864
1/3-7	NG	2/18	0.70	(2.4)	3.3	10.2	109	55.6	102	52.0	0	0	872	(1109)	56.3	0	--	--	--	--	35% Capacity, Tertiary Air Burner Pattern IIB (ports at 15° and 45° off radial)
1/3-8	NG	2/18	0.94	(3.2)	3.0	10.7	126	64.3	118	60.2	0	0	963	(1273)	54.9	0	--	--	--	--	50% Capacity, Tertiary Air Burner Pattern IIB

*Corrected to 3% O_2, Dry

(continued)

TABLE A-1 (Continued).

Test No.	Fuel	Date, 1978	Heat Input Rate		O_2, %	CO_2, %	NO_x		NO		CO	SO_2	Stack Temp.		Heater Efficiency %	Smoke Spot	ϕ_B	Staging Height		FGR %	Comments
			MW	(10^6Btu/h)			ppm*	ng/J	ppm*	ng/J	ppm*	ppm*	K	(°F)				m	(ft)		
1/3-9	NG	2/20	1.55	(5.3)	3.5	10.2	153	78.0	143	72.9	0	0	1162	(1631)	47.6	0	--	--	--	--	Baseline (80% Cap.) Tertiary Air Burner Pattern IIB
1/3-10	NG	2/20	1.55	(5.3)	0.4	11.3	122	62.2	117	59.7	83	0	1200	(1700)	50.9	0	--	--	--	--	O_2 swing, Tertiary Air Burner, Pattern IIB
1/3-11	NG	2/20	1.55	(5.3)	0.9	11.6	133	67.8	124	63.2	0	0	1200	(1701)	50.2	0	--	--	--	--	O_2 swing, Tertiary Air Burner, Pattern IIB
1/3-12	NG	2/20	1.55	(5.3)	2.1	11.2	149	76.0	141	71.9	0	0	1200	(1700)	48.6	0	--	--	--	--	O_2 swing, Tertiary Air Burner, Pattern IIB
1/3-13	NG	2/20	1.55	(5.3)	4.0	10.2	161	82.1	149	76.0	0	0	1193	(1688)	45.5	0	--	--	--	--	O_2 swing, Tertiary Air Burner, Pattern IIB
1/3-14	NG	2/20	1.90	(6.5)	3.2	10.3	155	79.1	146	74.5	0	0	1232	(1758)	45.8	0	--	--	--	--	100% Capacity, Tertiary Air Brn, Pattern IIB
1/3-15	Shale Oil	2/22	1.35	(4.6)	6.5	--	--	--	526	295	0	--	1099	(1519)	--	--	--	--	--	--	High O_2, Tertiary Air Burner, Tip 764, All Registers 100% Open
1/3-16	Shale Oil	2/22	1.14	(3.9)	3.2	--	--	--	439	246	0	--	1106	(1531)	--	--	--	--	--	--	Baseline O_2, Tertiary Air Brn, Tip 764, All Registers 100% Open
1/3-17	Shale Oil	2/22	1.29	(4.4)	2.0	--	--	--	364	204	0	214	1111	(1540)	--	--	--	--	--	--	Medium-Low O_2, Tertiary Air Brn, Tip 764, All Registers 50% Open
1/3-18	Shale Oil	2/22	1.29	(4.4)	0.35	--	--	--	200	112	>2000	--	1113	(1544)	--	--	--	--	--	--	Low O_2, Tertiary Air Burner, Tip 764
1/3-19	Shale Oil	2/22	1.20	(4.1)	1.2	--	--	--	295	165	0	--	1113	(1544)	--	--	--	--	--	--	Optimum-Low O_2, Tertiary Air Burner, Tip 764, PAR^1 = 25% Open, SAR^2 = 38% Open, TAR^3 = 100% Open
1/3-20	Shale Oil	2/22	1.29	(4.4)	3.0	--	349	196	329	185	0	--	1117	(1551)	--	--	--	--	--	--	Baseline O_2, Tertiary Air Burner, Tip 764, PAR = Closed SAR = 25% Open, TAR = 100% Open

*Corrected to 3% O_2, Dry

(continued)

TABLE A-1 (Continued).

Test No.	Fuel	Date, 1978	Heat Input Rate		O_2, %	CO_2, %	NO_x		NO		CO	SO_2	Stack Temp.		Heater Efficiency %	Smoke Spot	ϕ_B	Staging Height		FGR %	Comments
			MW	(10^6Btu/h)			ppm*	ng/J	ppm*	ng/J	ppm*	ppm*	K	(°F)				m	(ft)		
1/3-21	NG	2/22	1.41	(4.8)	3.4	--	--	--	148	75.5	0	0	1090	(1500)	50.7	--	--	--	--	--	Baseline, Tertiary Air Burner, Pattern IIB (ports at 15° and 45° off radial)
1/3-22	No.6	2/22	1.41	(4.8)	3.0	13.6	260	146	260	146	0	1357	1177	(1658)	51.4	0.5	--	--	--	--	Baseline, Tertiary Air Burner, Tip 864
1/3-23	No.6	2/22	1.38	(4.7)	3.2	12.6	194	109	192	108	0	1122	1179	(1662)	50.9	1	--	--	--	--	PAR = 1/8 open, SAR = TAR = 100% open, Tertiary Air Burner, Tip 864
1/3-24a	NG	2/23	1.47	(5.0)	3.1	10.3	79	40.3	75	38.3	0	0	1129	(1572)	49.5	0	--	--	--	--	Baseline, Tertiary Air Burner, Pattern IIC (2 firing ports, each 15° either side of radial)
1/3-24b	NG	2/23	1.47	(5.0)	3.7	10.2	98	50.0	93	47.4	0	0	1188	(1678)	45.8	0	--	--	--	--	Baseline, Tertiary Air Burner, Pattern IIC (2 firing ports, each 15° either side of radial), Higher Firebox Temperature
1/3-25	NG	2/23	1.41	(4.8)	3.2	10.6	85	43.4	84	42.8	0	0	1190	(1682)	46.5	0	--	--	--	--	Air Register Adjustments, Tertiary Air Burner, Pattern IIC
1/3-26	NG	2/23	1.41	(4.8)	2.9	11.0	84	42.8	80	40.8	0	0	1200	(1700)	46.6	0	--	--	--	--	Air Register Adjustments, Tertiary Air Burner, Pattern IIC
1/3-27	NG	2/23	1.47	(5.0)	3.0	11.0	88	44.9	83	42.3	0	0	1210	(1718)	46.1	0	--	--	--	--	Air Register Adjustments, Tertiary Air Burner, Pattern IIC
1/3-28	NG	2/23	1.47	(5.0)	3.2	10.2	94	47.9	92	46.9	0	0	1209	(1717)	45.8	0	--	--	--	--	Air Register Adjustments, Tertiary Air Burner, Pattern IIC
1/3-29	NG	2/23	1.49	(5.1)	3.2	10.2	95	48.5	90	45.9	0	0	1216	(1729)	45.6	0	--	--	--	--	Air Register Adjustments, Tertiary Air Burner, Pattern IIC
1/3-30	NG	2/23	1.49	(5.1)	2.9	10.8	86	43.9	84	42.8	0	0	1223	(1741)	45.9	0	--	--	--	--	Air Register Adjustments, Tertiary Air Burner, Pattern IIC
1/3-31	NG	2/23	1.49	(5.1)	3.4	10.6	89	45.4	86	43.9	0	0	1228	(1750)	44.7	0	--	--	--	--	Air Register Adjustments, Tertiary Air Burner, Pattern IIC
1/3-32	NG	2/23	1.49	(5.1)	3.5	10.3	96	49.0	96	49.0	0	0	1232	(1758)	44.4	0	--	--	--	--	Air Register Adjustments, Tertiary Air Burner, Pattern IIC

*Corrected to 3% O_2, Dry

(continued)

TABLE A-1 (Continued).

Test No.	Fuel	Date, 1978	Heat Input Rate		O_2, %	CO_2, %	NO_x		NO		CO	SO_2	Stack Temp.		Heater Efficiency %	Smoke Spot	ϕ_B	Staging Height		FGR %	Comments
			MW	(10^6Btu/h)			ppm*	ng/J	ppm*	ng/J	ppm*	ppm*	K	(°F)				m	(ft)		
1/3-33	NG	2/23	1.52	(5.2)	2.7	10.6	100	51.0	93	47.4	0	0	1236	(1765)	45.8	0	--	--	--	--	O_2 swing, Tertiary Air Burner, Pattern IIC, All Registers 100% Open
1/3-34	NG	2/23	1.49	(5.1)	2.1	10.6	76	38.8	76	38.8	47	0	1240	(1772)	46.8	0	--	--	--	--	O_2 swing, Tertiary Air Burner, Pattern IIC, All Registers 100% Open
1/3-35	NG	2/23	1.49	(5.1)	4.1	9.8	103	52.5	102	52.0	0	0	1241	(1773)	42.9	0	--	--	--	--	O_2 swing, Tertiary Air Burner, Pattern IIC, All Registers 100% Open
1/3-36	NG	2/23	1.49	(5.2)	3.2	10.6	101	51.5	92	46.9	0	0	1245	(1781)	44.5	0	--	--	--	--	O_2 swing at Optimum Reg. Setting, Tertiary Air Burner, Pattern IIC, PAR = 50% Open, SAR = TAR = 100% Open
1/3-37	NG	2/23	1.49	(5.2)	3.9	10.3	105	53.6	105	53.6	0	0	1244	(1780)	43.2	0	--	--	--	--	O_2 swing at Optimum Reg. Setting, Tertiary Air Burner, Pattern IIC, PAR = 50% Open, SAR = TAR = 100% Open
1/3-38	NG	2/23	1.49	(5.2)	2.2	11.0	75	38.3	75	38.3	57	0	1244	(1780)	46.4	0	--	--	--	--	O_2 swing at Optimum Reg. Setting, Tertiary Air Burner, Pattern IIC, PAR = 50% Open, SAR = TAR = 100% Open
1/3-39	No.6	2/24	1.41	(4.8)	3.1	13.6	268	150	262	147	0	1246	1104	(1527)	54.5	2	--	--	--	--	Baseline, Tertiary Air Burner, Tip 864
1/3-40	No.6	2/24	1.38	(4.7)	3.3	14.0	198	111	198	111	0	1237	1115	(1547)	53.6	3	--	--	--	--	Air Register Adjustments, Tertiary Air Burner, Tip 864
1/3-41	No.6	2/24	1.38	(4.7)	2.9	14.0	251	141	248	139	0	1166	1134	(1581)	53.4	1	--	--	--	--	Air Register Adjustments, Tertiary Air Burner, Tip 864
1/3-42	No.6	2/24	1.32	(4.5)	2.7	14.0	261	146	251	141	0	1258	1136	(1585)	53.5	0.5	--	--	--	--	Air Register Adjustments, Tertiary Air Burner, Tip 864
1/3-43	No.6	2/24	1.35	(4.6)	2.6	14.0	275	154	275	154	0	867	1138	(1589)	53.7	--	--	--	--	--	Air Register Adjustments, Tertiary Air Burner, Tip 864

*Corrected to 3% O_2, Dry

(continued)

TABLE A-1 (Continued).

Test No.	Fuel	Date, 1978	Heat Input Rate MW	Heat Input Rate (10^6Btu/h)	O_2, %	CO_2, %	NO_x ppm*	NO_x ng/J	NO ppm*	NO ng/J	CO ppm*	SO_2 ppm*	Stack Temp. K	Stack Temp. (°F)	Heater Efficiency %	Smoke Spot	ϕ_B	Staging Height m	Staging Height (ft)	FGR %	Comments
1/3-44	No.6	2/24	1.38	(4.7)	2.9	14.0	200	112	194	109	0	963	1141	(1594)	53.1	1	--	--	--	--	O_2 swing at Low-NO_x Register Setting, Tertiary Air Burner, Tip 864, PAR = 10% Open, SAR = TAR = 100% Open
1/3-45	No.6	2/24	1.38	(4.7)	3.4	13.2	205	115	205	115	0	844	1141	(1594)	52.1	0.5	--	--	--	--	O_2 swing at Low-NO_x Register Setting, Tertiary Air Burner, Tip 864, PAR = 10% Open, SAR = TAR = 100% Open
1/4-1	NG	3/13	1.55	(5.3)	3.4	10.4	99	50.5	94	47.9	0	--	941	(1234)	57.9	--	--	--	--	--	Baseline MA-16 Brn Pattern II
1/4-2	NG	3/13	1.52	(5.2)	2.6	10.2	100	51.0	98	50.0	0	--	1005	(1350)	56.3	--	--	--	--	--	PAR = 100% open, SAR = 50% open
1/4-3	NG	3/13	1.55	(5.3)	2.8	10.6	105	53.6	104	53.0	0	--	1033	(1399)	54.7	--	--	--	--	--	PAR = 100% open, SAR = 20% open
1/4-4	NG	3/13	1.58	(5.4)	2.9	11.0	110	56.1	108	55.0	0	--	1074	(1473)	52.8	--	--	--	--	--	PAR = 50% open, SAR = 50% open
1/4-5	NG	3/13	1.58	(5.4)	3.0	9.9	116	59.2	108	55.0	0	--	1113	(1544)	50.9	--	--	--	--	--	Baseline MA-16 Brn Pattern II
1/5-1	NG	3/13	1.58	(5.4)	3.4	10.0	64	32.6	64	32.6	0	--	--	--	--	--	--	--	--	--	50 lb/h steam inj
1/5-2	NG	3/13	1.58	(5.4)	3.3	10.0	60	30.6	60	30.6	0	--	--	--	--	--	--	--	--	--	78 lb/h steam inj
1/5-3	NG	3/13	1.58	(5.4)	2.8	10.6	69	35.2	69	35.2	0	--	--	--	--	--	--	--	--	--	50 lb/h steam inj
1/5-4	NG	3/13	1.58	(5.4)	3.2	11.3	89	45.4	89	45.4	0	--	--	--	--	--	--	--	--	--	Baseline, MA-16 Brn Pattern II
1/6-1	NG	3/14	1.58	(5.4)	3.2	10.1	103	52.5	102	52.0	0	--	1041	(1415)	53.7	--	1.17	--	--	--	Baseline, MA-16 Brn Pattern II
1/6-2	NG	3/14	1.52	(5.2)	3.0	10.2	74	37.7	73	37.2	0	--	1120	(1556)	50.6	--	0.85	0.61	(2)	--	Staged air
1/6-3	NG	3/14	1.47	(5.0)	3.7	9.9	75	38.3	72	36.7	0	--	1130	(1574)	49.1	--	0.88	0.91	(3)	--	Staged air
1/6-4	NG	3/14	1.38	(4.7)	2.6	10.4	62	31.6	62	31.6	0	--	1157	(1623)	49.7	--	0.8	1.22	(4)	--	Staged air
1/6-5	NG	3/14	1.47	(5.0)	3.0	10.6	65	33.2	65	33.2	0	--	1164	(1636)	48.6	--	0.84	1.52	(5)	--	Staged air
1/6-6	NG	3/14	1.58	(5.4)	0.9	11.3	40	20.4	39	19.9	0	--	1198	(1696)	50.5	--	0.75	1.52	(5)	--	Staged air, low O_2
1/6-7	NG	3/14	1.55	(5.3)	1.1	13.6	41	20.9	41	20.9	0	--	1215	(1727)	49.5	--	0.78	1.52	(5)	--	Staged air, low O_2
1/6-8	NG	3/14	1.52	(5.2)	2.7	10.6	79	40.3	75	38.3	0	--	1220	(1736)	46.9	--	0.87	1.52	(5)	--	Staged air
1/6-9	NG	3/14	1.44	(4.9)	2.5	10.6	120	61.2	116	59.2	0	--	1202	(1704)	47.9	--	1.12	--	--	--	Baseline, MA-16 Brn Pattern II
1/6-10	No.6	3/15	1.61	(5.5)	3.0	12.8	294	164.9	292	163.8	0	--	1119	(1555)	54.6	0	1.26	--	--	--	Baseline, MA-16 Brn Tip 764
1/6-11	No.6	3/15	1.58	(5.4)	2.7	14.8	183	102.7	177	99.3	0	--	1151	(1613)	53.7	3	0.92	0.91	(3)	--	Staged air
1/6-12	No.6	3/16	1.41	(4.8)	3.2	12.2	307	172.2	299	167.7	0	1230	980	(1305)	60.5	4	1.28	--	--	--	Baseline, MA-16 Brn Tip 764

*Corrected to 3% O_2, Dry

(continued)

TABLE A-1 (Continued).

Test No.	Fuel	Date, 1978	Heat Input Rate MW	Heat Input Rate (10^6Btu/h)	O_2, %	CO_2, %	NO_x ppm*	NO_x ng/J	NO ppm*	NO ng/J	CO ppm*	SO_2 ppm*	Stack Temp. K	Stack Temp. (°F)	Heater Efficiency %	Smoke Spot	ϕ_B	Staging Height m	Staging Height (ft)	FGR %	Comments
1/6-13	No.6	3/16	1.44	(4.9)	3.1	14.6	200	112.2	196	110.0	0	1214	998	(1336)	59.9	8	0.90	1.22	(4)	--	Staged air
1/6-14	No.6	3/16	1.44	(4.9)	1.0	15.6	149	83.6	144	80.8	0	1232	1060	(1448)	60.1	7	0.78	1.22	(4)	--	Staged air, low O_2
1/6-15	No.6	3/16	1.49	(5.1)	1.0	15.6	166	93.1	162	90.9	0	1213	1077	(1479)	59.3	7	0.85	1.22	(4)	--	Staged air, low O_2
1/6-16	No.6	3/16	1.61	(5.5)	3.3	13.6	203	113.9	203	113.9	0	1027	943	(1237)	62.1	3	0.99	1.22	(4)	--	Staged air
1/6-17	No.6	3/16	1.58	(5.4)	3.9	12.8	226	126.8	226	126.8	0	1067	1008	(1355)	58.4	8	1.03	1.22	(4)	--	Staged air
1/6-18	No.6	3/16	1.52	(5.2)	4.1	12.8	224	125.7	224	125.7	0	1030	1035	(1403)	56.7	3	0.98	1.22	(4)	--	Staged air
1/6-19	No.6	3/16	1.55	(5.3)	3.2	13.6	266	149.2	263	147.5	0	958	1073	(1471)	56.3	2	1.25	--	--	--	Baseline, MA-16 Brn Tip 764
1/7-1	NG	3/21	1.52	(5.2)	3.0	10.7	93	47.4	92	46.9	0	--	880	(1125)	61.1	--	--	--	--	--	Baseline
1/7-2	NG	3/21	1.47	(5.0)	2.8	10.6	79	40.3	78	39.8	0	--	1037	(1407)	54.6	--	--	--	--	15.7	Flue Gas Recirc
1/7-3	NG	3/21	1.49	(5.1)	2.8	10.6	77	39.3	74	37.7	0	--	1132	(1578)	50.5	--	--	--	--	15.4	Flue Gas Recirc
1/7-4	NG	3/21	1.52	(5.2)	2.9	10.6	84	42.8	83	42.3	0	--	1142	(1596)	49.8	--	--	--	--	11.6	Flue Gas Recirc
1/7-5	NG	3/21	1.41	(4.8)	2.1	11.2	43	21.9	42	21.4	0	--	1096	(1514)	53.2	--	--	--	--	40.2	Flue Gas Recirc, Low O_2
1/7-6	NG	3/21	1.41	(4.8)	3.0	10.8	48	24.5	47	24.0	0	--	1131	(1577)	50.1	--	--	--	--	36.9	Flue Gas Recirc
1/7-7	NG	3/21	1.41	(4.8)	2.1	11.2	47	24.0	47	24.0	0	--	1155	(1620)	50.7	--	--	--	--	38.2	Flue Gas Recirc, Low O_2
1/7-8	NG	3/21	1.52	(5.2)	0.7	12.8	43	21.9	42	21.4	31	--	1210	(1719)	50.3	--	--	--	--	36.9	Flue Gas Recirc, Low O_2
1/7-9	NG	3/21	1.58	(5.4)	3.4	10.8	116	59.2	110	56.1	0	--	1223	(1741)	45.4	--	--	--	--	--	Baseline
1/7-10	No.6	3/22	1.47	(5.0)	3.0	13.6	252	141.4	241	135.2	0	672	1056	(1441)	57.4	4.25	--	--	--	--	Baseline
1/7-11	No.6	3/22	1.47	(5.0)	3.2	13.2	194	108.8	192	107.7	0	--	1103	(1526)	55.0	2.5	--	--	--	19.3	Flue Gas Recirc
1/7-12	No.6	3/22	1.47	(5.0)	3.0	13.2	183	102.7	180	101.0	0	--	1110	(1538)	55.1	4	--	--	--	30.1	Flue Gas Recirc
1/7-13	No.6	3/22	1.49	(5.1)	3.0	13.2	174	97.6	172	96.5	0	--	1113	(1544)	54.9	4	--	--	--	37.5	Flue Gas Recirc
1/7-14	No.6	3/22	1.52	(5.2)	2.0	13.6	156	87.5	155	87.0	0	--	1135	(1583)	55.6	5	--	--	--	36.8	Flue Gas Recirc
1/7-15	No.6	3/22	1.52	(5.2)	2.0	13.0	172	96.5	170	95.4	0	--	1151	(1613)	54.9	4	--	--	--	27.8	Flue Gas Recirc
1/7-16	No.6	3/22	1.47	(5.0)	2.0	13.4	194	108.8	189	106.0	0	--	1174	(1653)	53.9	4	--	--	--	18.4	Flue Gas Recirc
1/7-17	No.6	3/22	1.47	(5.0)	0.8	15.0	171	95.9	169	94.8	9	--	1166	(1639)	56.1	6	--	--	--	20.6	Flue Gas Recirc, Low O_2
1/7-18	No.6	3/22	1.47	(5.0)	1.0	14.1	148	83.0	142	79.7	9	--	1180	(1665)	55.1	4	--	--	--	28.8	Flue Gas Recirc, Low O_2
1/7-19	No.6	3/22	1.44	(4.9)	1.0	13.8	155	87.0	153	85.8	0	--	1171	(1648)	55.5	2	--	--	--	37.6	Flue Gas Recirc, Low O_2
1/7-20	No.6	3/22	1.47	(5.0)	2.5	13.8	241	135.2	236	132.4	0	--	1173	(1652)	53.2	4	--	--	--	--	Baseline

*Corrected to 3% O_2, Dry

(continued)

TABLE A-1 (Continued).

Test No.	Fuel	Date, 1978	Heat Input Rate		O_2, %	CO_2, %	NO_x		NO		CO	SO_2	Stack Temp.		Heater Efficiency %	Smoke Spot	ϕ_B	Staging Height		PGR %	Comments
			MW	(10^6Btu/h)			ppm*	ng/J	ppm*	ng/J	ppm*	ppm*	K	(°F)				m	(ft)		
1/8-1	NG	4/26	1.47	(5.01)	3.0	10.2	66	33.7	64	32.6	0	0	1104	(1527)	50.8	0	--	--	--	--	Baseline, DBA-16 Brn Pattern II, firing ports toward tile, data questionable, sample line leak
1/8-2	NG	4/26	1.46	(4.99)	1.1	11.7	55	28.1	54	27.5	0	0	1158	(1625)	51.3	1	--	--	--	--	O_2 swing, same configuration as 1/8-1, data questionable, sample line leak
1/8-3	NG	4/26	1.54	(5.24)	0.3	12.0	--	--	48	24.5	152	0	1179	(1663)	51.5	2	--	--	--	--	O_2 swing, same configuration as 1/8-1, data questionable, sample line leak
1/8-4	NG	4/26	1.53	(5.22)	4.5	9.5	--	--	58	29.6	0	0	1169	(1644)	45.2	0	--	--	--	--	O_2 swing, same configuration as 1/8-1, data questionable, sample line leak
1/8-5	NG	4/26	1.52	(5.19)	3.1	9.9	--	--	55	28.1	0	0	1171	(1648)	47.6	0	--	--	--	--	O_2 swing, same configuration as 1/8-1, data questionable, sample line leak
1/8-6	NG	5/2	1.49	(5.10)	2.9	10.4	86	43.9	84	42.8	0	0	1098	(1517)	51.2	0	--	--	--	--	Baseline, DBA-16 Brn Pattern II, firing ports toward tile
1/8-7	NG	5/2	1.49	(5.07)	0.5	12.0	73	37.2	70	35.7	615	0	1113	(1543)	53.6	0.5	--	--	--	--	O_2 swing, same configuration as 1/8-6
1/8-8	NG	5/2	1.47	(5.03)	1.1	11.4	78	39.8	77	39.3	0	0	1119	(1554)	52.9	0	--	--	--	--	O_2 swing, same configuration as 1/8-6
1/8-9	NG	5/2	1.49	(5.07)	4.05	9.6	95	48.5	93	47.4	0	0	1115	(1547)	48.5	0	--	--	--	--	O_2 swing, same configuration as 1/8-6
1/8-10	NG	5/2	1.46	(5.00)	3.0	10.6	94	47.9	90	45.9	0	0	1118	(1552)	50.2	0	--	--	--	--	O_2 swing, same configuration as 1/8-6
1/9-1	NG	4/27	1.52	(5.18)	3.1	10.1	123	62.7	122	62.2	0	0	1133	(1581)	49.3	0	--	--	--	--	Baseline, DBA-16 Brn Pattern II, gas tips normal
1/9-2	NG	4/27	1.49	(5.08)	3.1	10.2	119	60.7	116	59.2	0	0	1156	(1622)	48.3	0	--	--	--	--	0.0067 Kg/s (53 lb/h) steam injection thru oil gun, oil gun 20 cm (8") below gas tips, DBA-16, Pattern II
1/9-3	NG	4/27	1.54	(5.24)	2.9	10.6	115	58.7	114	58.1	0	0	1172	(1651)	47.9	0	--	--	--	--	0.0067 Kg/s (53 lb/h) steam injection, oil gun 10 cm (4") below gas tips

*Corrected to 3% O_2, Dry

(continued)

TABLE A-1 (Continued).

Test No.	Fuel	Date, 1978	Heat Input Rate		O_2, %	CO_2, %	NO_x		NO		CO ppm*	SO_2 ppm*	Stack Temp.		Heater Efficiency %	Smoke Spot	ϕ_B	Staging Height		FGR %	Comments
			MW	(10^6Btu/h)			ppm*	ng/J	ppm*	ng/J			K	(°F)				m	(ft)		
1/9-4	NG	4/27	1.54	(5.24)	3.0	10.6	118	60.2	115	58.7	0	0	1183	(1670)	47.3	0	--	--	--	--	0.0067 kg/s (53 lb/h) steam injection, oil gun 5 cm (2") below gas tips
1/9-5	NG	4/27	1.55	(5.28)	3.0	10.6	114	58.1	110	56.1	0	0	1186	(1676)	47.1	0	--	--	--	--	0.0095 kg/s (75 lb/h) steam injection, oil gun 5 cm (2") below gas tips
1/9-6	NG	4/27	1.55	(5.28)	3.0	10.3	136	69.4	130	66.3	0	0	1193	(1687)	46.9	0	--	--	--	--	Repeat baseline, no steam injection
1/10-1	NG	4/28	1.49	(5.10)	3.0	10.2	145	74.0	142	72.4	0	0	1136	(1585)	49.4	0	--	--	--	--	Baseline, staging cyl. 7.6 cm (3") above gas tips, Pattern II
1/10-2	NG	4/28	1.51	(5.15)	3.1	9.9	115	58.7	113	57.6	0	0	1140	(1593)	49.0	0	--	--	--	--	Baseline, staging cyl. 15.2 cm (6") above gas tips, Pattern II
1/10-3	NG	4/28	1.48	(5.04)	3.2	9.9	98	50.0	94	47.9	0	0	1092	(1506)	51.0	0	--	--	--	--	Baseline, staging cyl. 22.9 cm (9") above gas tips, Pattern II
1/10-4	NG	5/1	1.50	(5.12)	3.0	10.3	88	44.9	84	42.8	0	0	1037	(1408)	53.7	0	--	--	--	--	Baseline, staging cyl. 94.0 cm (37") above gas tips, Pattern II
1/10-5	NG	5/1	1.61	(5.51)	3.1	10.6	94	47.9	88	44.9	0	0	1056	(1442)	52.7	0	--	--	--	--	Baseline, staging cyl. 109 cm (43") above gas tips, Pattern II
1/10-6	NG	5/1	1.55	(5.29)	4.9	9.6	114	58.1	110	56.1	0	0	1068	(1462)	49.3	0	--	--	--	--	O_2 swing, staging cyl. 109 cm (43") above tips, Pattern II
1/10-7	NG	5/1	1.57	(5.36)	1.2	11.8	66	33.7	66	33.7	0	0	1078	(1480)	54.5	0	--	--	--	--	O_2 swing, staging cyl. 109 cm (43") above tips, Pattern II
1/10-8	NG	5/1	1.54	(5.27)	0.5	12.0	54	27.5	53	27.0	439	0	1086	(1496)	54.8	0	--	--	--	--	O_2 swing, staging cyl. 109 cm (43") above tips, Pattern II
1/10-9	NG	5/1	1.56	(5.31)	3.1	10.5	87	44.4	86	43.9	0	0	1089	(1502)	51.2	0	--	--	--	--	O_2 swing, staging cyl. 109 cm (43") above tips, Pattern II

*Corrected to 3% O_2, Dry

(continued)

TABLE A-1 (Continued).

Test No.	Fuel	Date, 1978	Heat Input Rate		O_2, %	CO_2, %	NO_x		NO		CO	SO_2	Stack Temp.		Heater Efficiency %	Smoke Spot	ϕ_B	Staging Height		FGR %	Comments
			MW	(10^6Btu/h)			ppm*	ng/J	ppm*	ng/J	ppm*	ppm*	K	(°F)				m	(ft)		
1/11-1	NG	5/2	1.50	(5.12)	3.0	10.3	125	63.8	122	62.2	0	0	1059	(1447)	52.7	0	--	--	--	--	Baseline, DBA-16 Brn Pattern II
1/11-2	NG	5/2	1.50	(5.11)	1.1	11.1	114	58.1	110	56.1	0	0	1107	(1533)	53.3	0	--	--	--	--	O_2 swing, DBA-16 Brn Pattern II
1/11-3	NG	5/2	1.51	(5.14)	4.5	9.5	146	74.5	142	72.4	0	0	1108	(1535)	48.1	0	--	--	--	--	O_2 swing, DBA-16 Brn Pattern II
1/11-4	NG	5/2	1.43	(4.88)	0.3	12.0	103	52.5	97	49.5	678	0	1114	(1546)	53.8	1	--	--	--	--	O_2 swing, DBA-16 Brn Pattern II
1/11-5	NG	5/2	1.51	(5.14)	3.0	10.6	141	71.9	135	68.9	0	0	1115	(1547)	50.2	0	--	--	--	--	O_2 swing, DBA-16 Brn Pattern II
1/12-1	NG	5/3	1.54	(5.26)	3.0	10.6	101	51.5	96	49.0	0	0	1067	(1460)	52.4	0	--	--	--	--	Baseline, tertiary air brn. w/extended secondary tile, Pattern IIC
1/12-2	NG	5/3	1.53	(5.23)	1.3	11.5	90	45.9	87	44.4	0	0	1117	(1551)	52.7	0	--	--	--	--	O_2 swing, tertiary air brn. w/extended secondary tile, Pattern IIC
1/12-3	NG	5/3	1.55	(5.29)	0.5	11.7	88	44.9	82	41.8	193	0	1126	(1567)	53.3	0	--	--	--	--	O_2 swing, tertiary air brn. w/extended secondary tile, Pattern IIC
1/12-4	NG	5/3	1.52	(5.20)	3.0	10.2	111	56.6	108	55.1	0	0	1131	(1577)	49.5	0	--	--	--	--	O_2 swing, tertiary air brn. w/extended secondary tile, Pattern IIC
1/12-5	NG	5/3	1.52	(5.18)	4.2	9.9	114	58.1	111	56.6	0	0	1131	(1577)	47.6	0	--	--	--	--	O_2 swing, tertiary air brn. w/extended secondary tile, Pattern IIC
1/12-6	No.6	5/4	1.41	(4.8) est.	3.0	13.7	239	134.1	229	128.5	0	1135	1123	(1561)	54.0	1	--	--	--	--	Baseline, tertiary air brn. w/extended secondary tile, Tip 784
1/12/7	No.6	5/4	1.41	(4.8) est.	0.8	14.7	201	112.8	200	112.2	0	1127	1150	(1610)	56.2	1	--	--	--	--	O_2 swing, tertiary air brn. w/extended secondary tile, Tip 784
1/12-8	No.6	5/4	1.41	(4.8) est.	0.2	15.2	164	92.0	156	87.5	294	1422	1153	(1616)	56.9	2	--	--	--	--	O_2 swing, tertiary air brn. w/extended secondary tile, Tip 784

*Corrected to 3% O_2, Dry

(continued)

TABLE A-1 (Continued).

Test No.	Fuel	Date, 1978	Heat Input Rate		O_2, %	CO_2, %	NO_x		NO		CO	SO_2	Stack Temp.		Heater Efficiency %	Smoke Spot	ϕ_B	Staging Height		FGR %	Comments
			MW	(10^6Btu/h)			ppm*	ng/J	ppm*	ng/J	ppm*	ppm*	K	(°F)				m	(ft)		
1/12-9	No.6	5/4	1.41	(4.8) est.	3.1	13.6	237	133.0	231	130.0	0	972	1158	(1624)	52.2	1	--	--	--	--	O_2 swing, tertiary air brn. w/extended secondary tile, Tip 784
1/12-10	No.6	5/4	1.41	(4.8) est.	4.2	13.2	246	138.0	239	134.1	0	1208	1156	(1622)	50.3	0.5	--	--	--	--	O_2 swing, tertiary air brn. w/extended secondary tile, Tip 784

*Corrected to 3% O_2, Dry

[1] PAR = Primary Air Register

[2] SAR = Secondary Air Register

[3] TAR = Tertiary Air Register

APPENDIX B

CEMENT ASSOCIATION REPORT ON SUBSCALE KILN TESTS, LOCATION 2

KVB, Inc.

Portland Cement Pilot Kiln Runs - PHASE I
Effect of Changes in Sulfur Level and Water, Fly Ash and Dust Injection on Gaseous Emissions

January 1979

Submitted by

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Portland Cement Pilot Kiln Runs -

PHASE I

Effect of Changes in Sulfur Level and Water, Fly Ash and Dust Injection on Gaseous Emissions

Introduction

During the week of August 15-21, 1978, representatives of KVB, Inc. visited the Portland Cement Association, for the purpose of conducting pilot scale rotary cement kiln tests pursuant to PCA's proposal to KVB of May 25, 1978. These tests were to be a part of KVB's contract with the Federal EPA, in which the potential for reducing gaseous emissions from rotary cement kilns was to be assessed. Specifically, we were to evaluate the dependence of NO_x, SO_x, CO, and hydrocarbon emissions on the level of input sulfur, the use of water injection, and the insufflation of fly ash and cement plant kiln dust. In addition to operating and feeding the rotary kiln and collecting the clinker product, PCA was to assess the quality of the clinker product resulting from each set of process conditions evaluated. KVB was to monitor the kiln exit gas for the significant gaseous constituents.

Summary and Conclusions

Consistent with expectations, we found that NO_x emissions were affected most significantly by the burning zone temperature, tending to increase with increasing temperature as expected(1,2). The level of excess oxygen, surprisingly, did not have a very strong effect on NO_x emissions, except at very low oxygen levels where NO_x was appreciably suppressed and simultaneously CO emissions increased dramatically. The absolute level of NO_x emissions was far lower (by a factor of 10 or more) than would be expected for a typical production kiln with natural gas as fuel. We believe that this may be attributed to two basic factors:

1. The use of unheated secondary air.
2. The narrow diameter (5 in.) of the kiln.

Both of these factors result in decreased flame temperatures, and this in turn leads to a lower NO_x formation rate (by the Zeldovich mechanism)$^{(2)}$.

3. The high gas-to-solids ratio on this kiln as compared to a production kiln. This is especially relevant if, as seems likely, a considerable proportion of the NO_x emitted actually comes from nitrogen in the kiln feed.

There was little correlation between SO_2 and NO_x emission levels, except that very high SO_2 correlated with low NO_x if the excess oxygen level was also low. This suggests that sulfur can compete effectively with nitrogen for oxygen atoms in the hot zone of the flame. SO_2 emission in general correlated best with the level of sulfur in the fuel, although in all cases most of the sulfur in the kiln feed was lost, presumably by vaporization.

Hydrocarbon emission levels did not correlate well with anything except perhaps burning zone temperature and fuel sulfur. Even at 2-3% excess oxygen levels, there were still appreciable amounts of hydrocarbons emitted when the burning zone temperature fell below 2700°F and, simultaneously, large quantities of elemental sulfur were insufflated. It is not clear why this strange effect occurred.

The chemical properties of the clinker product were found to be reasonably independent of operating conditions within the range tested. Only the level of oxygen had any obvious effect on the clinker, reducing conditions leading to a decrease in ferrite reflectivity and an increase in alkali belite formation. Some of the other clinker properties were difficult to explain; for example, fly ash insufflation produced the best quality clinker, which would not have been expected. However, it was clear from the analyses that little, if any, of the insufflated materials (fly ash, kiln dust or sulfur), actually found their way into the clinker product. This was presumably due to the low probability of capture of dust particles in such a short kiln with a relatively high gas velocity. The situation would be very different in a full scale production kiln, especially a kiln system of the suspension preheater type, where virtually 100% capture would occur.

The major conclusions of this report, therefore, are that:

(i) Although it is now clear that NO_x emissions can be reduced by varying certain operating parameters such as fuel sulfur level and burning zone temperature, further tests must be carried out on a larger kiln if the true relationships are to be evaluated.

(ii) It is essential to use preheated secondary air in future. Moreover, the kiln preferably should be one which accepts unpelletized raw feed. In short, a plant test of the type described in Phase III of the research proposal will be essential to determine the full effect of operating conditions on NO_x and SO_x emissions.

(iii) The level of nitrogen in the raw feed is significant and may lead to emissions of NO_x comparable with those due to the flame. Future tests should evaluate this in terms of a complete nitrogen balance including raw feed, kiln dust and clinker. The chemical state of the nitrogen also should be determined.

The PCA Pilot - Scale Rotary Kiln

All tests at PCA were run on a 15-ft long pilot-scale rotary kiln with a 5-in. internal diameter. The kiln is shown schematically in Figure 1. The kiln feed is generally provided in the form of pellets, because with unpelletized feed the dust losses from a small kiln are enormous, due to the high gas velocity in comparison with a typical production-scale kiln.

The PCA kiln has a straight burner pipe utilizing natural gas. The secondary air flow is capable of regulation, but is not preheated (as opposed to the case of a typical production kiln). The draft through the kiln is provided by an induced draft (I.D.) fan on the stack.

The inclination and speed of rotation of the kiln can be controlled in order to determine the residence time of feed pellets in the kiln. Hot clinker pellets drop several feet from the kiln exit into a collecting tray, and are cooled appreciably during the fall. Kiln dust can be collected from both the dust box and the cyclone dust collector.

Also shown in Figure 1 are the two points at which the KVB gas-monitoring probe was inserted. Not shown is the position of PCA's own probe for oxygen monitoring. This was generally positioned so that it extended several inches into the kiln at the back end near the tip of the feed pipe.

Experimental Method and Results

The PCA rotary kiln was operated for a period of six working days during which all tests included in Phase I of the research program were carried out. However, due to some temporary technical problems, the tests were not conducted exactly in the manner planned; most of the useful gas analysis results were obtained during the last four days of testing.

Operational parameters and exhaust gas compositions for selected times during the test period are given in Table 1. This table contains the following data:

1. Date and time of readings (as close as possible).
2. Kiln fuel consumption (cubic feet per minute of natural gas).
3. Kiln feed rate (lbs/hour of pelletized kiln feed).
4. Burning-zone temperature (measured by optical pyrometer).
5. Feed pipe temperature (measured by a thermocouple near the base of the feed pipe).
6. Cyclone inlet temperature (the temperature of the gases entering the cyclone dust collector at the back end of the kiln, measured by thermocouple).

7. Oxygen at back end of kiln: This was measured by PCA, using a "fyrite" volumetric oxygen monitor attached to a probe inside the back of the kiln.

8. Kiln shell temperature: This was measured in the area of maximum shell temperature, i.e., the flame zone, using "tempilstiks".

The following gas measurements were carried out by KVB:

9. Sample position: This refers to the position of the gas probe, which was normally in the dust-box but sometimes in the cyclone outlet. It is notable that O_2 levels at the cyclone outlet are much higher than in the dust box, due to air inleakage.

10. Percentage of oxygen in kiln exhaust gases (O_2).

11. Nitric oxide in kiln gases (NO). It should be noted that NO_2 levels were also measured but were generally negligible; it can be assumed, therefore, that total NO_x levels are equal to the NO measurement within experimental error.

12. Carbon dioxide in kiln gases (CO_2).

13. Carbon monoxide in kiln gases (CO).

14. Hydrocarbons in kiln gases (HC).

15. Sulfur dioxide in kiln gases (SO_2).

16. Atmospheric temperature (in °F).

17. Atmospheric pressure (in inches of mercury).

18. The rate of addition of any secondary materials: Sulfur, kiln dust, and fly ash were added to the kiln

by insufflation at the burner end. Water was also added at the burner end by means of a spray nozzle.

19. Feed type: Only one basic kiln feed was used, but in preliminary tests it was found to be too "coarse". It was then reground and repelletized after which it is referred to as "fine".

20. Feed sulfur: The level of sulfur in the original kiln feed was low. A high-sulfur feed was produced by adding 1% gypsum to the original kiln feed.

The chemical analyses and potential cement compound composition of the kiln feeds are given in Table 2. Analyses of the fly ash and kiln dust used in the insufflation runs are given in Table 3. It should be noted that the "high-sulfur" kiln feed was produced by adding 1% gypsum to the standard kiln feed; therefore, its ultimate calculated compound content should be the same as that of the low-sulfur feed except for $CaSO_4$ content. In practice, much of the sulfur content of both feeds was lost during the heat treatment. In any case, their final clinker compositions would be expected to be almost identical. (The so-called "coarse" kiln feed was the original low sulfur feed material.)

Clinker and Other Solid Samples

Due to limitations of sample size (because of the low production rate of the pilot kiln), many of the solid samples, (i.e., clinker and cyclone dusts), which were collected during the kiln run, had to be combined to give "composite" samples large enough for the detailed analyses which had been prescribed. As a result, the exact time of collection cannot be given for all the samples collected; however, the kiln operating conditions for each of the composite samples were approximately constant, and thus the exact collecting times are not required for the analyses. Six pairs of clinker samples were collected under conditions such that, for each pair, only one major operational variable was altered (taking on a relatively "high" or "low" value). The other variables were maintained as constant as possible within each sample pair, although it was not possible to maintain absolute constancy throughout the whole sampling period. The twelve samples are listed in Table 4, together with operating conditions during their collection periods. (The "PDC" numbers given for the samples are simply arbitrary reference numbers used to identify the samples in the laboratory.)

The twelve clinker samples listed in Table 4 were examined under the optical microscope, using the "polished section" technique. The results are listed in Table 5. The twelve clinkers were also analyzed semi-quantitatively by powder x-ray diffraction; the results of these analyses are given in Table 6 as approximate weight percentages of the major clinker compounds.

From these twelve clinkers and other clinker samples collected during the run, seven "composite" clinkers were made up, by grinding together several clinkers. The seven composite clinkers were chosen to represent the following kiln operating conditions:

1. High levels of water injection, (high-sulfur feed).
2. High levels of kiln dust insufflation, (low-sulfur feed).
3. High levels of fly ash insufflation, (low-sulfur feed).
4. "Standard" conditions, i.e., no insufflation, ("coarse" low-sulfur feed).
5. High levels of sulfur insufflation and high-sulfur feed.
6. High levels of sulfur insufflation and low-sulfur feed.
7. "Standard" conditions, i.e., no insufflation, (high-sulfur feed).

The results of semi-quantitative x-ray diffraction analyses of these cements are given in Table 7. The sulfur content of each of the seven clinker composites was determined by the "Leco" method, and is shown in Table 8, (together with the sulfur analyses of the two kiln feeds and one of the cyclone dust collected during the run). The composite clinkers were ground in a ball mill together with sufficient gypsum to give a total sulfate content of 3.2% (as SO_3) in the finished cement. All seven cements were ground to approximately the same Blaine fineness, as is shown in Table 9. The number of mill revolutions required to give the desired cement fineness from a 2.5 kg clinker batch is also shown in this table, so as to give a rough idea of the relative grindabilities of the cements. Finally, compressive strength tests were carried out on 2-in. mortar cubes made from the cements, using the ASTM C109 procedure. The compressive strengths at 1, 3, 7, and 28 days are also given in Table 9.

In addition to the clinker samples, many samples of the dust from the cyclone at the back end of the kiln were collected during the run. Generally, the amounts of dust collected were small, and so they were combined into six composite samples for analysis. These composites were combinations of dusts collected under similar operating conditions, as shown in Table 10; the table also gives the results of the x-ray diffraction examination of these dusts, which expressed in the form of a rough "order of abundance" of the various compounds detected.

Discussion of Results

NO Emission Levels

The levels of NO emission are very low in comparison with those of typical cement kilns, which are typically in the range of 400-2,000 ppm, according to Miller(1). In fact, Miller's results show that the average NO_x emission from gas-fired cement kilns is as high as 1,350 ppm, i.e., a factor of ten higher than the highest results obtained on the pilot-scale kiln. There are probably two major reasons for this discrepancy, namely:

(i) Low secondary air temperature: Normal cement kilns operate with secondary air preheated by passage through the clinker cooler, whereas the PCA kiln has no such preheat. This will effectively mean a lower peak flame temperature in the PCA kiln; and flame temperature is known to be a major factor in NO_x production especially in gas flames (i.e., the "Zeldovich" mechanism)(2).

(ii) The small kiln diameter: The PCA kiln is only 5 in. I.D., whereas a typical cement kiln is likely to have an I.D. of 10-20 ft. This means that the surface-to-volume ratio of the hot gases inside the kiln is perhaps a factor of 25-50 greater than that of a typical cement kiln, and this will result in an appreciable increase in the rate of heat loss from the flame zone in the PCA kiln, relative to a production kiln, (even though the gas velocities in the PCA kiln are also appreciably higher, and gas emissivities are appreciably lower, than in a production kiln, both of which work counter to this argument). This will again tend to reduce peak flame temperature and thus reduce NO_x emissions by the same mechanism as suggested in (i).

Regardless of the low total NO_x emissions, the relative results in Table 1 are of significance. First of all, however, it should be noted that there is a considerable difference between results obtained where sampling at the cyclone outlet and at the dust box; this is because of appreciable air inleakage between the dust box and the cyclone outlet, which typically amounts to about 9% excess O_2, i.e., an air inleakage equal to about 43% of the total gas downstream of the cyclone, or a factor of 0.75 relative to the gas at the kiln exit. (This is determined by comparing the oxygen levels at the back end of the kiln with those at the cyclone outlet). As a result of this, it was decided to use the "Dust Box" monitoring point in all the later runs, even though the gas temperatures were rather high (about 1100-1200°F) at this point.

Figure 2 is a plot of NO emissions (corrected to zero excess O_2) against burning zone temperature for all the kiln runs in which no material such as S, H_2O, FA or KD was insufflated. There is clearly a large degree of scatter in the results, which nevertheless do indicate a tendency for NO emission to increase as burning zone temperature increases. Also shown on this graph are the excess oxygen levels measured by the monitor at the back end of the kiln. Surprisingly, there appears to be little correlation between excess air and NO emission in these results. This is peculiar, because if the NO is formed by the Zeldovich mechanism, it would be expected to increase considerably as the excess oxygen level increased, providing that burning zone temperature remained approximately constant$^{(2)}$. This is because the Zeldovich mechanism involves the reaction oxygen atoms produced by the dissociation of excess oxygen:

$$O_2 \rightleftarrows O + O \qquad \ldots\ldots (1)$$

$$O + N_2 \xrightarrow{k_2} NO + N \qquad \ldots\ldots (2)$$

$$N + O_2 \xrightarrow{k_3} NO + O \qquad \ldots\ldots (3)$$

Reaction 1 is assumed to be near equilibrium with the excess oxygen at the flame temperature. Rate constant k_2 is much smaller than k_3, so Reaction 2 controls the rate of NO formation. This mechanism is, of course, a rather simplistic view of the total NO production in a flame, but it does nevertheless give a good explanation for the facts normally observed, i.e., the strong temperature dependence, (which is due to the high activation energy for Reaction 2, and the position of the equilibrium constant for Reaction 1) and also the positive dependence on excess oxygen. However, the results obtained in our study do not conform well to this mechanism, and this may be in part due to rather low overall flame temperatures, which result in low absolute NO levels as discussed earlier. At low flame temperatures, other mechanisms may be producing NO; for example, the "Fenimore" mechanism$^{(2)}$:

$$CH + N_2 \rightleftarrows HCN + N \quad \text{.....} \quad (4)$$

$$N + O_2 \rightarrow NO + O \quad \text{.....} \quad (5)$$

It also seems likely that much of the scatter in our results may have been due to difficulties in controlling the burning conditions adequately. The excess O_2 level measured at the back end of the kiln is also influenced to some degree by air entering with the kiln feed and around the kiln seal.

Correlation of NO emissions with CO and SO_2

Another correlation of interest is given in Figure 3, where NO emission is plotted against both CO emission and SO_2 emission. (In this case, all the test results were included and no correction for excess O_2 was made.) This graph does indicate that there is some degree of inverse correlation between NO and CO, and also between NO and SO_2, as was found in Miller's results$^{(1)}$. Certainly, when NO levels are relatively high, the SO_2 and CO levels tend to be relatively low. However, there is no really strong inverse correlation, in the range of intermediate concentrations, between NO and SO_2. There is a slightly better inverse correlation between NO and CO, which would be expected simply due to the fact that high levels of CO indicate an oxygen deficiency in the flame zone, and this will reduce NO_x formation (by the Zeldovich mechanism, etc.).

It should be noted, however, that when very high levels of sulfur were insufflated into the flame zone at low excess air levels, there was an appreciable drop in NO_x emission (see Table 1). This effect is best shown in the results for 8/17 at 14:15 to 16:25 hours. The addition of sulfur to the flame at low excess oxygen levels does decrease NO_x emissions dramatically. However, at high excess oxygen levels, the insufflation of sulfur has only a small effect (e.g., 8/18 at 14:30 hours). It seems likely, therefore, that sulfur helps to "mop-up" excess oxygen atoms in the flame zone before they have time to react with nitrogen molecules. However, the detailed mechanism of such a reaction would be difficult to ascertain at present; it presumably leads ultimately to the formation of SO_2 or SO_3.

Nitrogen Content of Kiln Feed and Products

Total nitrogen content was determined (by the Kjeldahl method) on four solid samples: the low-sulfur kiln feed, clinkers PDC 125 and 126, and the cylone dust PDC 112. The results are shown in Table 11.

In an attempt to further determine the chemical state of the nitrogen, several solid samples including clinker PDC 126, and the kiln feed material, were boiled with concentrated NaOH solution, but no smell of ammonia could be detected. Aluminum powder was then added; but again, no smell of ammonia was detected. Therefore, it is as yet uncertain whether the nitrogen in the various solid samples was present as nitrides, nitrates, or in some other form.

It is interesting to note that the nitrogen levels in both feed and clinker are significant. The clinker contains almost no nitrogen when burnt under oxidizing conditions, but it contains almost 50% of the feed nitrogen when burnt under reducing conditions. This suggests that the nitrogen is trapped in the form of nitrides, and this may explain why certain cements are known to give a smell of ammonia when mixed with water.

On the assumption that all the feed nitrogen were to be driven off as nitrogen dioxide during clinkering under oxidizing conditions, this particular kiln feed would give rise to about 8.5 lbs of NO_2 per ton of clinker produced. This amount of NO_2 is of the same order of magnitude as the typical emission level for most cement plants(1), and thus cannot be ignored in any discussion of kiln NO_2 emissions. The exact nature of the nitrogen in the kiln feed is uncertain, but in this particular case, since the feed contains no kerogenous shale material, it is possible that much of the nitrogen is in the form of nitrates or nitrites in the limestone. If kerogens were present in the feed, we would also expect some organically bound nitrogen to be present.

In the case of our present kiln runs, the typical gas flow through the kiln would be about 50 SCFM, and a typical clinker production rate would have been about 5 lbs/hr; this should have given rise to about 55 ppm of NO_x in the kiln exit gases under oxidizing conditions. It can be seen, therefore, that most of the NO_x emission from the kiln may be accounted for by feed nitrogen levels, especially under oxidizing conditions. This does help to explain the observed variation in NO_x emissions, which decrease appreciably when CO levels are high, i.e., when strongly reducing conditions occur in the burning zone. The observation that feed nitrogen can account for a significant proportion of kiln NO_x emissions is an important one, and should be followed up by further investigation at the later stages of this project. Interestingly, potassium nitrate (KNO_3) is known to decompose at about 800°C to give nitrogen oxides$^{(4)}$; this temperature is similar to the calcining temperature of calcite. Calcium nitrate is known to melt at 561°C; its decomposition temperature is unknown, but probably below 800°C. Thus, decomposition of nitrates in kiln feed could occur in the later stages of the preheater in a suspension-preheater or precalciner kiln. This may mean that the presence of reducing conditions in the calcining zone itself could help to reduce NO_x emissions significantly, by reducing any molten nitrates or nitrites directly.

SO_2 Emissions

Apart from the periods during or immediately after the insufflation of sulfur into the flame zone, the levels of SO_2 in the kiln exit gas never exceeded 100 ppm, which is rather low for a long dry kiln. However, the low level is probably mainly due to the very high gas-to-solid ratio for the PCA kiln, (in comparison with a production kiln). The level of SO_2 emission which would result if all the feed sulfur from the low-sulfur feed were vaporized as SO_2 would be about 0.034 lb/ hour, and on the basis of a gas flow through the kiln of 50 SCFM, this should give about 64 ppm SO_2 in the kiln exit gases. The high-sulfur feed should give nearly twice this amount. These figures are of the same order of magnitude as the observations in Table 1. Of course, the observed SO_2 levels are lower than calculated because some SO_2 ends up as sulfates in the clinker and in the cyclone dust, etc. The level of sulfate in the cyclone dust is higher than in the kiln feed, as is shown in Table 9. The results otherwise do suggest, as expected, that SO_2 emissions are higher when the level of sulfate in either the feed or in the fuel is higher, and also when the excess oxygen levels are lower; this was especially true for the fly-ash insufflation results (8/21 14:35 to 15:50). It is interesting to note that SO_2 levels were very low during the insufflation of kiln dust (8/21 9:40 to 10:45), even though the kiln dust contained high levels of sulfate. This suggests that sulfates are not decomposed rapidly in an oxidizing atmosphere.

The Effects of Kiln Dust, Fly Ash and Water Insufflation on Gaseous Emissions

Comparison of the results for 8/18 at 15:25 and at 16:25 suggest that water injection into the flame zone has little or no effect on NO_x emissions. The only significant change was an apparent increase in CO levels from 25 to 55 ppm and a decrease in hydrocarbon emissions from 115 to 65 ppm. It is not clear whether this is due to water injection or to the small change in the excess oxygen level.

Again, with fly ash insufflation (8/21 14:35 to 15:50), there was no evidence that fly ash itself had any effect on NO_x or SO_x emissions; however, at these low excess oxygen levels the NO levels were very sensitive to flame conditions -- the one low value at 14:45 apparently occurred at a very low excess oxygen level of 0.05%. The second series of fly ash tests were carried out at more realistic oxygen levels (8/21, 16:10 - 17:35), but again did not show any really clear effects, although the NO emission levels were somewhat lower than might have been expected.

The results of the kiln dust insufflation tests on 8/21 (9:40 - 10:45) shows no significant change in NO emission levels. (The SO_2 emission was effectively zero during this period, even though the kiln dust contains high levels of sulfate.) It may be concluded that reactions between the gases and the insufflated fly ash or kiln dust contributed little to the final composition of the kiln exit gases. However, the same might not necessarily be true for a production-scale cement kiln, especially a suspension preheater kiln, where gas-solid contact occurs very efficiently in the preheater cyclones.

Analyses of the twelve clinker samples

The main differences shown by the microscopic examination (in Table 5) have to do with oxidizing or reducing conditions; PDC 126 was collected at low excess O_2 (0.1%) and not surprisingly was strongly reduced clinker. However, PDC 113 clinker also showed reducing conditions, which was surprising considering that it was collected during a period of relatively high kiln oxygen levels (1.4%). There is no obvious reason why water injection should have lead to reducing conditions in the kiln. The mildly reducing conditions determined from clinkers PDC 132, 129, and 119 are consistent with the fairly low kiln oxygen levels for these samples (0.5% O_2 at back end). Generally, the microscopic results do not show any other significant differences between the clinkers. However, there does appear to be some correlation between alkali-belites and mildly reducing conditions. Also, PDC 143, which had a coarse kiln feed, showed large belite clusters which are generally indicative of oversized quartz particles in the kiln feed.

The results of the x-ray diffraction analyses of these clinkers (Table 6) also show few significant differences between them. It is notable that the coarse feed gave the highest free lime content (and correspondingly low C_3S content) especially at a low burning-zone temperature (PDC 143), as would be expected. Virtually all the other differences were small and difficult to explain; for instance, fly ash addition (PDC 132) should decrease C_3S at the expense of C_2S, but there was no indication of this having occurred. Sulfur insufflation (PDC 109) decreased C_3S levels, possibly with the formation of alkali and calcium sulfates; however, these were not detected in any great amount in the clinker. Water injection (PDC 113) also apparently lowered the C_3S level somewhat, which is not easy to explain, but suggests that the reducing conditions noted in Table 5 were genuine and may have led to some alite decomposition.

The Results of the Tests on Seven Composite Clinkers

Table 7 contains the results of x-ray diffraction analyses of the seven "composite" clinkers. They are not identical with the corresponding clinkers in Table 6 because each of them is a composite of several clinkers, many of which were not analyzed individually. Table 8 shows the sulfur content of the seven clinkers; it is notable that Clinker 1 contains much more SO_3 than the others, and much of this sulfur appears to be present in the form of anhydrite ($CaSO_4$). All the clinkers show a considerable loss of sulfur relative to the kiln feed, which is not surprising for a short dry-process kiln. However, it is not at all clear why Clinker 5 should have such a low sulfur level, considering that both the feed and the fuel were high in sulfur in this case.

The results of the compressive strength tests on mortar cubes made from the seven cements, (produced by grinding the seven clinker composites with sufficient gypsum to give 3.2% total SO_3), are given in Table 9. In general, the low early strengths of Samples 4 and 7 appear to correspond with their low C_3S levels. Cement No. 3 gives the best results at all ages; its high early strength may be due more to its high surface area than anything else. (It was by far the most easily grindable of the clinkers). It is still not clear to us exactly why the insufflation of fly ash should result in such high quality clinker. In fact, since the fly ash contains mainly silica and alumina, it should have reduced the C_3S content of the clinker appreciably and thus lowered the early strengths. Our results suggest that virtually none of the fly ash was incorporated in the clinker pellets, presumably because the high gas velocity and short kiln resulted in a very low probability for fly ash capture, and also because the feed was pelletized. In a full-scale cement plant, this would not generally be the case.

Although no very strong conclusions can be drawn from the observed cement properties, it does appear that insufflation of sulfur, kiln dust, fly ash and water into the flame zone of the kiln all had slightly beneficial effects on the properties of the cement product. This may be due to the increased heat emissivity of the flame; (heat transfer occurs mainly by radiation in the hot zone). This would suggest that an increase in flame emissivity is a useful asset especially in a small rotary kiln where the optical path-length is short. In a large kiln, however (3), the optical path-length is generally long enough such that any change in gas composition due to the addition of dust or emitting gases (e.g. SO_2, CO_2, H_2O) will only marginally affect the overall emissivity of the gas (as "seen" by the kiln charge).

One further conclusion to be drawn from these results is that neither the sulfur from the feed or from the fuel had much effect on sulfur level in the clinker. This is mainly due to the low probability of sulfur recapture in the kiln, because it is a very short dry-process kiln. Again, (as for fly ash), the probability of sulfur recapture would be far greater in a typical production-scale kiln, and especially in a preheater kiln. In such kilns, much of the fuel and feed sulfur will end up in the clinker, especially under oxidizing conditions.

Cyclone Dusts

Table 10 contains the results of x-ray diffraction analyses of six cyclone dusts collected during the kiln run. These were generally very small samples collected over a long period of time, (due to the low rate of dust collection in the cyclone). The approximate operating conditions during the collection period are shown in the table.

Virtually all the dusts contain mainly calcite and quartz, i.e. unaltered raw feed components. However, they also contain fairly high amounts of free lime and β-C_2S, which are produced from the feed inside the kiln at intermediate temperatures. These dust components are presumably the result of pellet abrasion, etc. It is interesting to note that dust No. 122 contains a relatively large amount of C_2S; this is probably because the kiln-dust which was insufflated at that time was of suitable composition to give C_2S by itself when subject to heat treatment (see Table 3). This further confirms the earlier findings that material which was insufflated into the kiln had little, if any, opportunity to react with the pelletized kiln feed material.

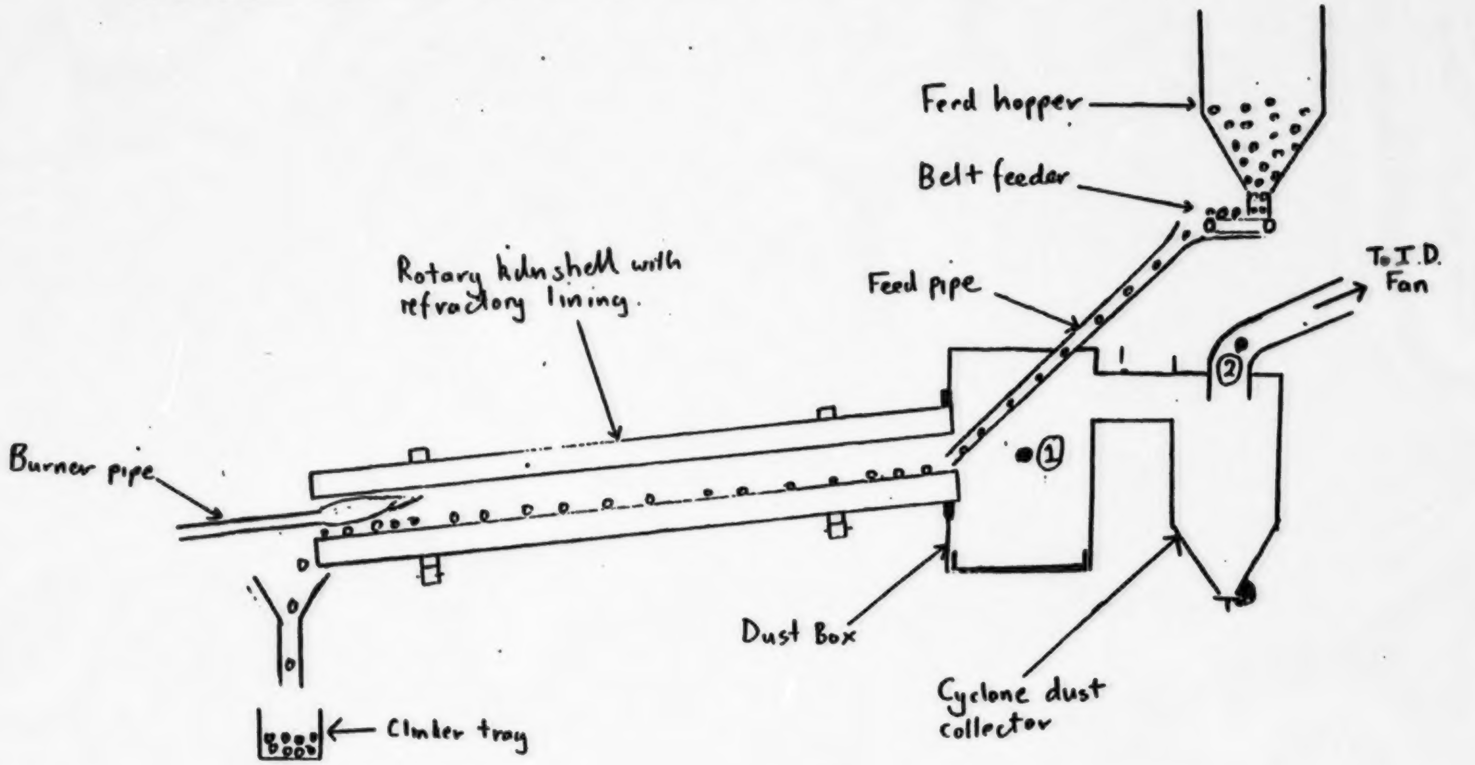
The only other results of significance are:

(i) PDC 153 shows that high levels of sulfur insufflation lead to high levels of simple sulfates ($CaSO_4$ and K_2SO_4) in the kiln dust. The total sulfur level in the dust is far greater than that of the kiln feed (see Table 8).

(ii) PDC 112 apparently suggests that water injection helps in the formation of complex sulfates such as aphthitalite and calcium langbeinite, at the expense of the simple sulfates (arcanite and anhydrite). This is an interesting result and should be the object of further investigation. Kiln dust insufflation also leads to high levels of the complex sulfates, but this is probably mainly due to the very high sulfur content of the original kiln dust which was insufflated.

It is not surprising that sulfur in the kiln system tends to be converted to sulfates in the kiln dust. This is part of the normal alkali and sulfur cycle in typical cement kilns(3).

FIGURE 1: PCA ROTARY KILN (SCHEMATIC)


Feed hopper
Belt feeder
To I.D. Fan
Feed pipe
Rotary kilnshell with refractory lining.
①
②
Burner pipe
Dust Box
Cyclone dust collector
Clinker tray

① = Gas Sampling Port in Dust Box

② : Gas Sampling Port at Cyclone Outlet.

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4. Freeman, E.S., Journal of the American Chemical Society, Vol. 79, pp. 838-42, 1957.

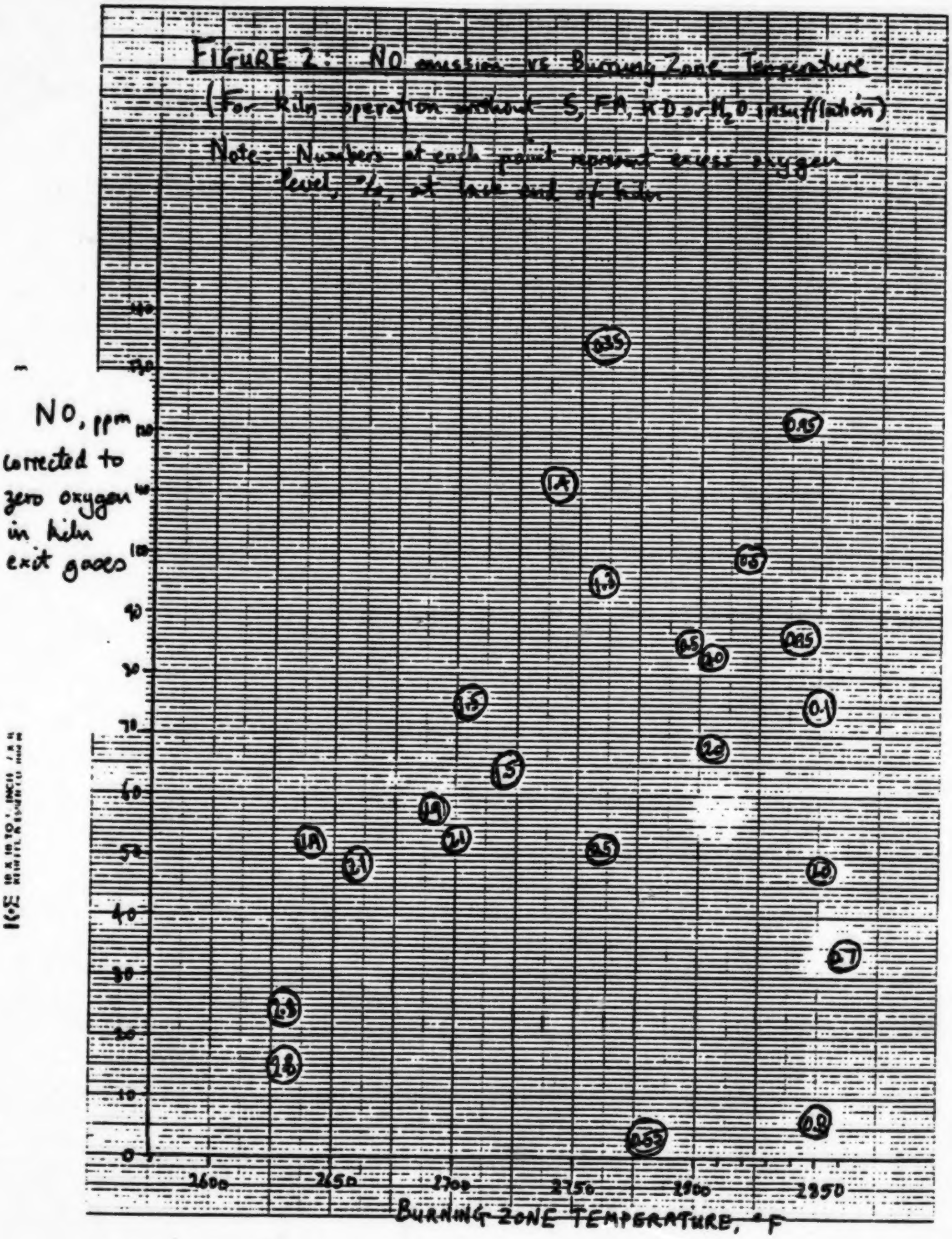

FIGURE 2: NO emission vs Burning Zone Temperature

(For kiln operation without S, FA, KD or H_2O insufflation)

Note: Numbers at each point represent excess oxygen level, %, at back end of kiln.

K+E 46 1333

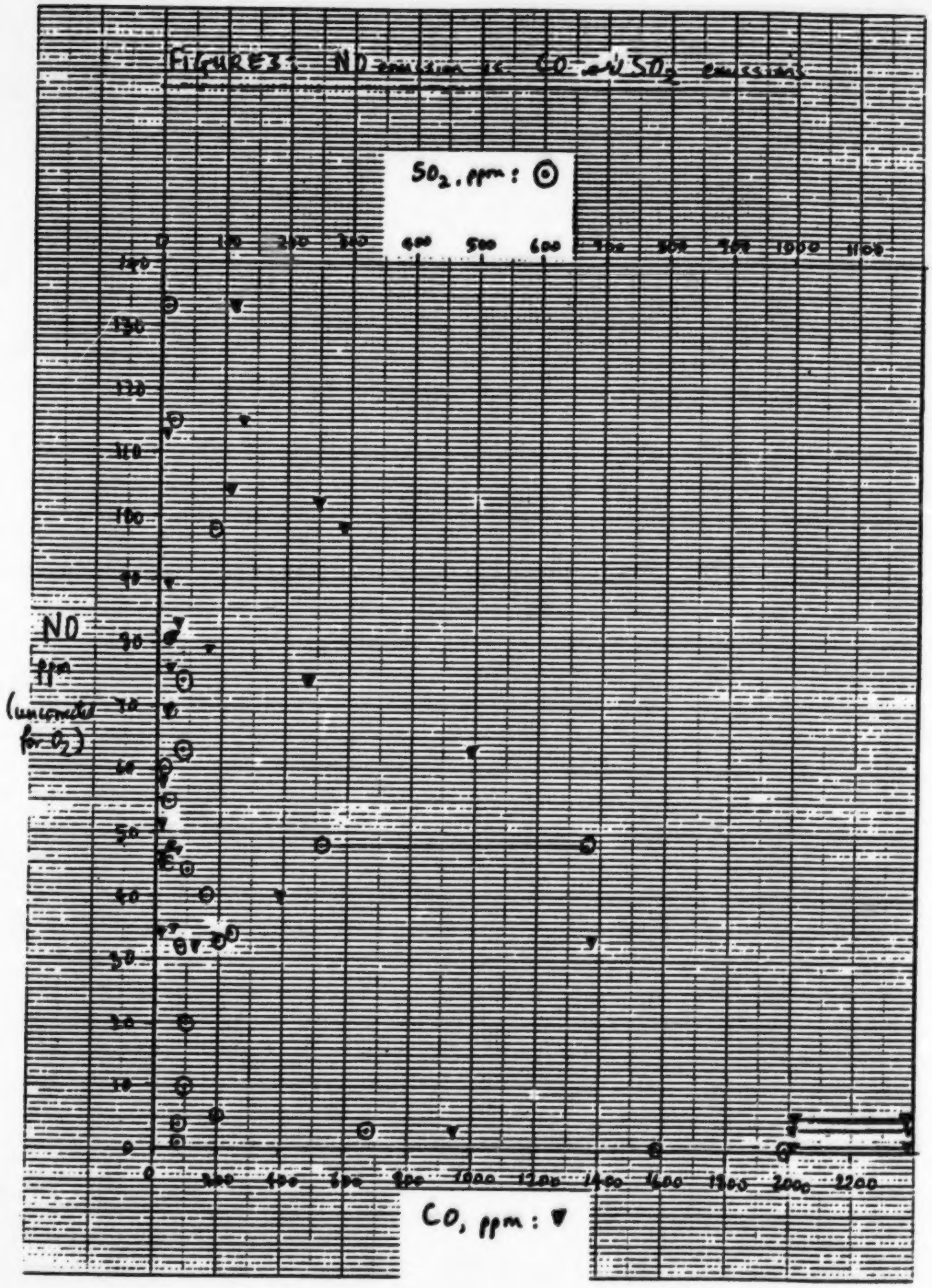

FIGURE 3: NO emission vs. CO and SO2 emissions

TABLE 1. SUMMARY OF KILN RUNS

Date	Time	Fuel Cons. CFM	Feed lbs/hr	Burn Zone Temp °F	Feed Pipe Temp °F	Cyc. Inlet Temp °F	O_2 Back End, %	Kiln Shell Temp °F	Sampling Point**	O_2 %	NO ppm	CO_2 %	CO ppm	HC ppm	SO_2 ppm	Atm. Temp °F	Atm. Press in.Hg.	Addition*	Feed Fineness	Feed SO_3
8/15	14:05	4.58	9.0	2850	1010	1140	1.0	625	CO	10.0- 10.6	32	6.05	125	30	40	—	29.15	None	Coarse	Low
8/16	9:15	4.54	4.8	2860	1010	1175	—	700-800	DB	0.7	33	12.8	1375	--	100	--	--	None	Coarse	High
8/16	12:00	4.35	0	2805	1010	1158	2.0	625	CO	10.5	45	6.2	10	32	0	--	--	None	--	--
8/16	12:20	4.35	0	2805	1010	1158	2.0	625	DB	0.64	81	12.6	50	--	20	--	--	None	--	--
8/16	13:35	4.35	10.2	2760	985	1115	0.5	640	CO	9.75	35	6.4	60	20	—	74	29.13	None	Coarse	High
8/16	13:45	4.54	10.2	2795	990	1115	0.5	640	DB	0.60	83	12.0	60	--	0	74	29.13	None	Coarse	High
8/16	14:15	4.54	10.2	2840	1000	1120	0.95	650	CO	9.90	58	5.6	20	--	0	80	29.15	None	Coarse	High
8/16	14:25	4.54	10.2	2840	1000	1120	0.95	650	DB	1.60	113	10.8	20	--	—	80	29.15	None	Coarse	High
8/16	16:50	4.58	11.0	2820	970	1085	0.5	640	DB	0.2	98	9.2	580	--	88	80	29.15	None	Coarse	High
8/16	17:25	4.58	8.5	2810	990	1090	1.6	650	CO	8.82	40	9.0	390	24	80	80	29.15	60 g S/hr	Coarse	High
8/16	17:55	4.26	2.0	2630	1000	1105	2.8	625	DB	4.60	20	7.6	None	0	50	78	29.18	None	Coarse	High
8/16	17:55	4.26	2.0	2630	1000	1105	2.8	625	CO	10.60	10	--	None	--	50	78	29.18	None	Coarse	High
8/17	12:10	4.58	8.4	2850	950	1100	0.8	750	DB	0.22	5.5	12.65	>2000	48	100	78	29.34	None	Coarse	High
8/17	14:15	4.47	8.4	2850	940	1068	0.1	640	DB	0.20	74	13.4	470	35	40	81	29.32	None	Fine	Low
8/17	14:30	4.47	8.4	2790	940	1068	0.0	640	DB	0.15	1.0	12.4	>2000	25	40	81	29.32	280 g S/hr	Fine	Low
8/17	14:45	4.47	8.4	2760	940	1068	—	640	DB	0.10	0	12.4	>2000	--	1000	81	29.32	960 g S/hr	Fine	Low
8/17	16:25	4.54	6.2	2775	950	1050	0.3	640	DB	0.20	0	11.9	>2000	60	792	83	29.24	402 g S/hr	Fine	Low
8/17	16:40	4.47	6.2	2780	940	1060	0.55	640	DB	0.40	3	11.9	950	--	334	82	29.24	None	Fine	Low
8/18	10:05	4.38	7.4	2705	1000	1070	1.5	640	DB	1.8	69	12.0	30	68	20	76	29.30	None	Fine	Low
8/18	10:35	4.31	7.4	2710	990	1058	2.35	640	DB	3.0	60	11.5	20	75	10	76	29.30	270 g S/hr	Fine	Low
8/18	11:50	4.31	7.4	2690	980	1048	1.9	640	DB	2.84	51	10.4	20	75	0	76	29.26	None	Fine	High
8/18	14:20	4.31	3.6	2700	990	1040	2.1	640	DB	3.1	46	9.9	20	35	0	83	29.20	None	Fine	High
8/18	14:30	4.31	3.6	2700	990	1045	3.4	640	DB	3.8	34	9.4	20	100	120	83	29.20	312 g S/hr	Fine	High
8/18	15:00	4.31	6.0	2640	970	1040	1.9	640	DB	3.1	45	10.2	20	--	15	85	29.17	None	Fine	High

Continued on next page ...

TABLE 1. SUMMARY OF KILN RUNS (Continued)

Date	Time	Fuel Cons. CFM	Feed lbs/hr	Burn Zone Temp °F	Feed Pipe Temp °F	Cyc. Inlet Temp °F	O_2 Back End, %	Kiln Shell Temp °F	Sampling Point**	O_2 %	NO ppm	CO_2 %	CO ppm	HC ppm	SO_2 ppm	Atm. Temp °F	Atm. Press in.Hg.	Addition*	Feed Fineness	Feed SO_3
8/18	15:05	4.31	6.0	2670	970	1045	2.2	640	DB	2.4	48	10.4	50	130	260-680	85	29.17	500 g S/hr	Fine	High
8/18	15:25	4.54	6.0	2660	980	1035	2.1	640	DB	2.55	44	10.2	25	115	50	85	29.20	None	Fine	High
8/18	15:40	4.54	6.0	2770	980	1038	1.85	640	DB	2.05	46	10.6	25	95	20	85	29.20	360 g H_2O/hr	Fine	High
8/18	16:15	4.51	6.0	2705	970	1048	1.95	650	DB	2.2	55	10.6	25	70	20	87	29.17	655 g H_2O/hr	Fine	High
8/18	16:25	4.51	6.0	2680	970	1050	1.8	650	DB	2.05	47	10.6	55	65	20	87	29.17	1600 g H_2O/hr	Fine	High
8/18	16:40	4.51	6.0	2720	970	1045	1.5	640	DB	1.7	59	12.0	25	83	10	87	29.17	None	Fine	High
8/21	9:40	4.06	4.8	2670	900	985	1.3	600	DB	1.6	70	11.2	30	12	0	74	29.64	70g KD/hr	Fine	Low
8/21	10:00	4.06	4.8	2590	890	990	1.5	625	DB	1.5	71	11.6	25	10	0	74	29.64	210g KD/hr	Fine	Low
8/21	10:45	4.10	6.0	2600	890	990	1.3	625	DB	1.6	78	11.2	30	9	0	74	29.64	150g KD/hr	Fine	Low
8/21	14:35	4.20	6.0	2770	890	985	0-0.02	670	DB	0.18	63	12.8	990	21	40	—	29.59	60g FA/hr	Fine	Low
8/21	14:45	4.20	6.0	2755	890	980	0.05	680	DB	0.05	3.8	12.5	>2000	50	40	79	29.59	180g FA/hr	Fine	Low
8/21	15:30	4.20	6.0	2720	885	970	0.35	675	DB	0.4	115	13.2	260	18	20	78	29.59	60g FA/hr	Fine	Low
8/21	15:50	4.26	6.0	2750	890	965	0.50	670	DB	0.3	102	13.2	500-2000	14	0	78	29.58	180g FA/hr	Fine	Low
8/21	16:10	4.18	6.0	2760	890	970	0.35	670	DB	0.3	133	12.8	228	12	10	77	29.57	None	Fine	Low
8/21	16:55	4.18	6.0	2760	890	970	1.3	675	DB	1.5	89	11.8	30	20	0	77	29.57	None	Fine	Low
8/21	17:10	4.20	6.0	2765	885	980	1.55	670	DB	1.5	79	11.7	160	12	0	76	29.55	66g FA/hr	Fine	Low
8/21	17:25	4.20	6.0	2700	850	970	1.65	675	DB	1.8	76	11.7	40	8	0	75	29.54	200g FA/hr	Fine	Low
8/21	17:35	4.18	6.0	2740	890	970	1.4	670	DB	1.6	104	11.6	218	11	0	75	29.54	None	Fine	Low

*Note: Additions of sulfur (S), water (H_2O), kiln dust (KD), and fly ash (FA) were made at the burner end of the kiln.

**Note: CO = cyclone outlet, DB = Dust Box

TABLE 2 - CHEMICAL ANALYSIS OF KILN FEEDS

Oxide	(% by Weight)			
	Kiln Feed Without Gypsum		Kiln Feed With Gypsum	
	As Is	Ignited Basis	As Is	Ignited Basis
SiO_2	14.23	22.55	14.08	22.37
Al_2O_3	3.49	5.53	3.46	5.50
Fe_2O_3	1.65	2.62	1.63	2.59
CaO	39.90	63.23	39.48	62.74
MgO	2.24	3.55	2.22	3.53
SO_3	0.53	0.81	0.99	1.57
K_2O	0.96	1.52	0.95	1.51
Na_2O	0.12	0.19	0.12	0.19
L.O.I.	36.88	--	37.07	--

Calculated Clinker Composition for Feed Without Gypsum

C_3S	45.13%
C_2S	30.60%
C_3A	10.22%
C_4AF	7.97%
Lime Saturation Factor	89.0
Silica Ratio (S/A + F)	2.77
Iron Modulus (A/F)	2.11
Liquid Phase	26.6%
Burnability Factor	103.8

Note: This calculated composition ignores the presence of MgO, alkalies and sulfates in the clinker

TABLE 3 - ANALYSES OF INSUFFLATED MATERIALS

Oxides, % by Weight	Fly Ash	Kiln Dust
SiO_2	53.20	14.60
Al_2O_3	28.70	4.00
Fe_2O_3	9.50	2.20
CaO	1.31	43.50
MgO	1.02	1.23
SO_3	0.40	16.90
Na_2O	0.58	0.39
K_2O	3.06	5.57
P_2O_5	0.37	0.07
TiO_2	1.66	0.19
F^-	--	0.21
Cl^-	--	0.45
L.O.I.	3.07	10.20

TABLE 4. OPERATING CONDITIONS DURING COLLECTION OF CLINKER SAMPLES

Clinker Sample Number	Burning Conditions (Major Variables)	Date	Time (approx.)	Approximate Burning Zone Temperature ^{o}F During Collection	Approximate O_2 level at back end, %, During Collection	Feed Type	Other Comments
PDC 125	High Oxygen	8/21	17:10	2760	1.6	Fine feed without gypsum	Fly-ash addition at 60 g/hr
PDC 126	Low Oxygen	8/21	14:20	2760	0.1	Fine feed without gypsum	Fly-ash addition at 60 g/hr
PDC 132	High Fly-Ash Additions	8/21	16:05	2760	0.3-0.4	Find feed without gypusm	Fly-ash addition at 180 g/hr
PDC 129	Low Fly-Ash Additions	8/21	15:30	2750	0.3-0.4	Find feed without gypsum	No fly-ash addition
PDC 119	High Kiln-Dust Additions	8/21	12:00	2700	0.5	Fine feed without gypsum	Kiln-dust addition at 180 g/hr
PDC 120	Low Kiln-Dust Additions	8/21	9:30	2680	1.3	Fine feed without gypsum	No kiln-dust addition
PDC 109	High Sulfur Insufflation Rate	8/18	15:00	2700	2.0	Fine feed without gypsum	Sulfur added at 120 g/hr
PDC 108	Low Sulfur Insufflation Rate	8/18	9:15	2760	1.0-2.0	Fine feed without gypsum	No sulfur added

Continued on next page ...

TABLE 4. OPERATING CONDITIONS DURING COLLECTION OF CLINKER SAMPLES (Continued)

Clinker Sample Number	Burning Conditions (Major Variables)	Date	Time (approx.)	Approximate Burning Zone Temperature °F During Collection	Approximate O_2 level at back end, %, During Collection	Feed Type	Other Comments
PDC 113	High Water Addition Rate	8/18	15:55	2700	1.4	Fine feed without gypsum	H_2O added at 360 ml/hr
PDC 115	Low Water Addition Rate	8/18	12:25	2700	1.9	Fine feed with gypsum	No H_2O added
PDC 145	High Burning Temperature	8/15	16:15	2800-2850	0.5-1.0	Coarse feed without gypsum	No additions
PDC 143	Low Burning Temperature	8/15	11:30	2650-2700	0.5-1.0	Coarse feed without gypsum	No additions

TABLE 5. MICROSCOPIC EXAMINATION OF TWELVE CLINKER SAMPLES

Variable: (Either High or Low)	Clinker:Composition	Oxygen Level	Fly Ash Addition	Kiln Dust Addition	Sulfur Insufflation	Water Injection	Burning Zone Temperature
"High"	PDC No.	125	132	119	109	113	145
	Alkali Sulfates	minute quantity	trace	minute quantity	minute quantity	minute quantity	trace
	Periclase	trace	trace	trace	trace	trace	trace
	Free Lime	more than a trace	more than a trace	trace	trace	trace	more than a trace
	Alite Properties	Small (20-40 μm) and well-formed	Good size range (20-40 μm), well-formed crystals	Small (20-35 μm); some decomposition was apparent	Small (20-35 μm) and well-formed	Small-to-medium (20-40 μm); slight evidence of decomposition	Small-to-medium (20-40 μm) crystals; some belite fringes indicate some decomposition
	Belite Properties	Well-formed, (20-30 μm); some small clusters	Small-to-medium crystals (15-25 μm) mainly in medium-size clusters	Size 20-30 μm, small clusters; some raggedness and some alkali-belites	Well-formed crystals (20-35 μm), in small clusters	20-30 μm crystals in medium clusters some indications of alkali belite	Good size (20-35 μm) crystals, mainly in clusters
	C_3A	Abundant; small-to-medium crystals	Normal abundance; small-to-medium crystals	Abundant; small-to-medium crystals	Abundant; small-to-medium crystals	Abundant; small-to-medium crystals	Small crystals
	C_4AF	Scarce, but good reflectivity	Normal abundance; fair reflectivity	Scarce, with fair reflectivity	Scarce, but good reflectivity	Scarce, with very low reflectivity	Scarce, but with good reflectivity
	Other Comments	Good quality clinker	Mildly reducing conditions are indicated	Mildly reducing conditions are indicated	Good quality clinker	Reducing conditions are indicated	Good quality clinker

Continued on next page ...

TABLE 5. MICROSCOPIC EXAMINATION OF TWELVE CLINKER SAMPLES (Continued)

Variable: (Either High or Low)	Clinker:Composition	Oxygen Level	Fly Ash Addition	Kiln Dust Addition	Sulfur Insufflation	Water Injection	Burning Zone Temperature
"Low"	PDC No.	126	129	120	108	115	143
	Alkali Sulfates	minute quantity	minute quantity	minute quantity	minute quantity	minute quantity	minute quantity
	Periclase	trace	trace	trace	trace	trace	trace
	Free Lime	trace	none detected	none detected	trace	trace	trace
	Alite Properties	Small (20-35 μm) and well-formed crystals; slight decomposition	Small-to-medium (20-40 μm), and fairly well-formed	Small-to-medium crystals (20-40 μm) and well-formed	Small (20-35 μm) and well-formed	Small-to-medium (20-40 μm); crystals; fairly well-formed	Small, well-formed crystals (20-35 μm); apparently suggest a low peak temperature
	Belite Properties	Medium-size clusters; slight raggedness evident; (20-40 μm)	Medium-size crystals (20-30 μm) in medium-size clusters	Medium-size crystals (20-30 μm), mainly in clusters	Well-formed crystals in small clusters	Crystals in small or medium clusters; some tendency to alkali belite appearance	Medium clusters of 10-20 μm and 30-50 μm crystals. Larger crystals are tightly clustered.
	C_3A	Abundant; small-to-medium crystals	Abundant; medium-size crystals	Abundant; small-to-medium crystals	Abundant; small-to-medium crystals	Abundant; small-to-medium crystals	Medium crystals
	C_4AF	Scarce, low reflectivity	Scarce, low reflectivity	Scarce, fair-to-good reflectivity	Scarce, but good reflectivity	Scarce, fair-to-good reflectivity	Normal-to-low abundance, variable reflectivity
	Other Comments	Some clinker pellets had extremely yellow centers; very porous clinker. Strongly reducing conditions	Reducing conditions are indicated	Good quality clinker	Good quality clinker	Good quality clinker	Belite clusters indicate that kiln feed is too coarse

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TABLE 6 - X-RAY DIFFRACTION ANALYSIS OF TWELVE CLINKER SAMPLES

Variable: (High or Low)	Clinker Composition* (% by weight)	Oxygen Level	Fly Ash Addition	Kiln Dust Addition	Sulfur Insufflation	Water Injection	Burning Zone Temperature
"High"	PDC No.	125	132	119	109	113	145
	C_3S	55-60	55-60	55-60	50-55	50-55	50-55
	C_2S	20-25	20-25	20-25	25-30	25-30	20-25
	C_3A	10-12	10-12	10-12	8-10	8-10	10-12
	C_4AF	4-6	4-6	3-5	4-6	4-6	4-6
	Periclase	1-1.5	1-1.5	1-1.5	1-1.5	1-1.5	1-1.5
	Free Lime	<1	<1<	<1	<1	1-1.25	1-1.25
	K_2SO_4	trace	trace	small amount	trace	trace	trace
"Low"	PDC No.	126	129	120	108	115	143
	C_3S	55-60	55-60	50-55	55-60	55-60	45-50
	C_2S	20-25	20-22	25-30	20-25	20-25	25-30
	C_3A	10-12	10-12	10-12	10-12	8-10	8-10
	C_4AF	4-6	4-6	4-6	3-5	4-6	3-5
	Periclase	1-1.5	1-1.5	1-1.5	1-1.5	1-1.5	1-1.5
	Free Lime	<0.5	<1	1-1.5	<0.5	<1	1.5-3
	K_2SO_4	small amount	trace	trace	small amount	trace	small amount

*Note: These values represent estimates of clinker composition obtained from peak height intensities in the x-ray diffraction patterns.

TABLE 7. CLINKER COMPOSITES: X-RAY DIFFRACTION ANALYSES

Clinker Composite No.*	Burning Conditions	Type of Kiln Feed	Compound Composition of Clinker, % by weight**							
			C_3S	C_2S	C_3A	C_4AF	Periclase	Free Lime	K_2SO_4	Others
1	Water Injection	Fine feed with gypsum	50-55	25-30	8-10	3-5	1.5-2	<1	trace	some anhydrite
2	Kiln Dust Insufflation	Fine feed without gypsum	50-55	25-30	11-13	4-6	1	<1	small amount	a trace of quartz
3	Fly Ash Insufflation	Fine feed without gypsum	50-55	25-30	10-12	4-6	1-2	<0.5	more than a trace	a trace of quartz
4	Standard	Coarse feed without gypsum	45-50	30-35	10-12	4-6	1.5-2	1	trace	--
5	High Level of Sulfur Insufflation	Fine feed with gypsum	50-55	25-30	12-14	3-5	1.5-2	1-1.3	trace	--
6	High Level of Sulfur Insufflation	Fine feed without gypsum	48-52	25-30	10-12	4-6	2-3	2-3	trace	--
7	Standard	Fine feed with gypsum	45-50	30-35	8-10	5-7	2-3	1.5-2	small amount	a trace of quartz and of calcium langbeinite

Notes: *These clinkers were made up as composites of several clinker samples taken at different times; therefore, feed type and burning conditions as shown in the table were not absolutely constant over the whole sample, but represent reasonable average values.

**These were estimated from peak heights in the x-ray diffraction patterns.

TABLE 8 - TOTAL SULFUR ANALYSES BY THE LECO METHOD

Sample	Total Sulfur as SO_3, Wt. %	Comments
Kiln Feed Without Gypsum	0.53	This was the basic kiln feed
Kiln Feed With Gypsum	0.99	1% gypsum added to basic kiln feed
Cyclone Dust, PDC 153	4.53	This is a composite sample of cyclone dust, collected during a period of high sulfur insufflation
Clinker Composites (Numbers as in Table 7)		% Gypsum Interground to Give a Cement with 3.2% Total SO_3 Content
1	0.66	5.51
2	0.18	6.55
3	0.08	6.76
4	0.10	6.72
5	0.09	6.74
6	0.18	6.55
7	0.21	6.48

TABLE 9 - RESULTS OF COMPRESSIVE STRENGTH TESTS*

Cement** No.	Number[+] of Mill revolutions	Blaine Fineness cm^2/g	Amount of gypsum added, wt. %	Compressive Strength, psi,			
				1 Day	3 Days	7 Days	28 Days
1	--	3,508	5.51	1,238	2,338	3,988	6,258
2	3,970	3,534	6.55	1,000	2,775	4,112	6,108
3	2,500	3,869	6.76	1,288	3,050	4,862	6,533
4	3,750	3,553	6.72	825	2,500	3,625	5,892
5	--	3,704	6.74	1,225	2,700	3,662	5,800
6	4,600	3,680	6.55	975	2,625	3,675	5,800
7	4,308	3,603	6.48	912	2,450	3,406	5,625

Notes: *These tests were carried out on 2-in. mortar cubes following the standard ASTM C109 procedure, except that only two cubes each were tested at 1, 3, and 7 days due to a shortage of cement; all strength results are averages and at 28 days are averages of 3 cubes.

**These numbers are defined on page 9.

[+] Using 2.5 kg batches of clinker plus gypsum in a steel ball mill.

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TABLE 10. RESULTS OF X-RAY DIFFRACTION ANALYSES OF CYCLONE DUSTS

Cyclone Dust: PDC No.	Operating Conditions When Dust Was Collected	Compounds Detected by XRD; (Numbers indicate approximate order of abundance estimated from peak heights)											
		Calcite ($CaCO_3$)	Quartz (SiO_2)	Free Lime (CaO)	Belite (β-C_2S)	Spurrite ($2C_2S\cdot C\overline{C}$)	Anhydrite ($CaSO_4$)	Arcanite (K_2SO_4)	Sylvite (KCl)	Aphthitalite ($(K,Na)_2SO_4$)	Calcium Langbeinite ($2CaSO_4\cdot K_2SO_4$)	Periclase (MgO)	Others
136	Low excess oxygen; high level of kiln-dust insufflation	1	2	4	3	6	6	5	trace	--	--	--	trace of muscovite and microcline
137	High excess oxygen; after fly ash insufflation	1	2	3	3	trace	5	4	trace	--	trace	trace	--
153	High level of sulfur insufflation	1	3	2	3	4	4	3	--	--	--	trace	Some $Ca(OH)_2$
112	High level of water injection	1	4	2	3	7	6	5	8	8	8	--	--
111	High level of sulfur insufflation; no gypsum in feed	1	4	2	3	5	6	4	trace	7	trace	--	--
122	After kiln-dust insufflation; no gypsum in feed	2	3	3	1	5	4	4	--	6	4	--	--

TABLE 11 - TOTAL NITROGEN ANALYSES

Material	Operating Conditions During Collection	Total Nitrogen, ppm
Kiln Feed (without gypsum)	--	831
Cyclone Dust PDC 112	High Level of Water Injection	151
Clinker PDC 125	High Excess Oxygen Level (Fine feed without gypsum, fly ash addition at 60 g/hr)	<7
Clinker PDC 126	Low Excess Oxygen Level (Fine feed without gypsum, fly ash addition at 60 g/hr)	567

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APPENDIX C

SUMMARY OF GASEOUS EMISSION DATA

LOCATION 4,

SUBSCALE STEEL FURNACE

TABLE C-1. SUMMARY OF GASEOUS EMISSION DATA, LOCATION 4, SUBSCALE STEEL FURNACE

Test No.	Fuel	Date, 1979	Heat Input Rate	O_2	CO_2	NO_x		NO		CO	HC	SO_2	SO_3	Stack Temp		Furnace Effic.	FGR	Water/Steam Injection Rate		Comments
			MW (10^6 Btu/h)	%	%	ppm*	ng/J	ppm*	ng/J	ppm*	ppm*	ppm*	ppm*	K	(°F)	%	%	g/s	(lb/h)	
4/1-1	NG	7/12	0.29 (1.0)	4.17	9.2	N/A		128	66.1	64	N/A	N/A	-	1458	(2165)	24.5	----	-		Excess O_2 variation at half capacity.
4/1-2	NG	7/12	0.29 (1.0)	1.90	10.2	N/A		216	111.6	56	N/A	N/A	-	1559	(2346)	24.1	----	-		2% O_2, half capacity
4/1-3	NG	7/12	0.29 (1.0)	0.45	11.6	N/A		180	93.0	473	N/A	N/A	-	1594	(2410)	27.9	----	-		Excess O_2 variation at half capacity.
4/1-4	NG	7/12	0.29 (1.0)	4.25	9.2	N/A		160	82.7	11	N/A	N/A	-	1406	(2071)	26.5	----	-		Excess O_2 variation at half capacity.
4/2-1	NG	7/12	0.59 (2.0)	3.1	9.9	N/A		181	93.5	23	N/A	N/A	-	1547	(2325)	26.9	----	-		Excess O_2 variation at full capacity.
4/2-2	NG	7/12	0.59 (2.0)	4.1	8.9	N/A		168	86.6	11	N/A	N/A	-	1523	(2282)	23.2	----	-		Excess O_2 variation at full capacity.
4/2-3	NG	7/12	0.59 (2.0)	2.0	10.8	N/A		189	97.6	57	N/A	N/A	-	1578	(2380)	29.0	----	-		Baseline
4/2-4	NG	7/12	0.59 (2.0)	0.2	11.5	N/A		192	99.2	312	N/A	N/A	-	1604	(2428)	30.7	----	-		Excess O_2 variation at full capacity.
4/3-1	NG	7/13	0.59 (2.0)	1.90	10.3	N/A		203	104.9	52	N/A	N/A	-	1514	(2265)	30.0	----	0		Baseline
4/3-2	NG	7/13	0.59 (2.0)	1.95	10.2	N/A		118	61.0	57	N/A	N/A	-	1519	(2275)	27.0	----	2.52	(20.0)	Water Injection
4/3-3	NG	7/13	0.59 (2.0)	1.92	10.1	N/A		141	72.8	61	N/A	N/A	-	1516	(2270)	27.3	----	1.89	(15.0)	Water Injection
4/3-4	NG	7/13	0.59 (2.0)	1.98	10.1	N/A		156	80.6	39	N/A	N/A	-	1522	(2280)	27.6	----	1.26	(10.0)	Water Injection
4/3-5	NG	7/13	0.59 (2.0)	2.00	10.2	N/A		166	85.8	43	N/A	N/A	-	1533	(2300)	28.2	----	.63	(5.0)	Water Injection
4/3-6	NG	7/13	0.59 (2.0)	2.05	9.9	N/A		185	95.6	43	N/A	N/A	-	1536	(2305)	27.4	----	0		Atomizing air only - no Water Injection
4/3-7	NG	7/13	0.59 (2.0)	1.90	10.2	N/A		207	106.9	56	N/A	N/A	-	1533	(2299)	28.7	----	0		Baseline
4/3-8	NG	7/27	0.59 (2.0)	2.02	11.1	186	96.1	186	96.1	10	10	0	-	1551	(2332)	31.3	----	0		Baseline
4/3-9	NG	7/27	0.59 (2.0)	2.00	11.3	130	67.2	130	67.2	6	13	0	-	1551	(2333)	29.8	----	2.52	(20.0)	Water Injection
4/3-10	NG	7/27	0.59 (2.0)	2.17	10.1	105	54.2	105	54.2	6	13	0	-	1544	(2320)	24.7	----	3.78	(30.0)	Water Injection
4/3-11	NG	7/27	0.59 (2.0)	2.20	10.1	98	50.6	98	50.6	7	11	0	-	1533	(2300)	24.0	----	5.04	(40.0)	Water Injection
4/3-12	NG	7/27	0.59 (2.0)	1.81	10.6	24	12.4	24	12.4	7	11	0	-	1555	(2340)	-	16.9	5.04	(40.0)	Maximum Water Injection plus maximum FGR
4/4-1	NG	7/18	0.59 (2.0)	4.10	9.4	N/A		117	60.4	48	N/A	N/A	-	1550	(2330)	22.0	4.9	-		5% FGR, High O_2
4/4-2	NG	7/18	0.59 (2.0)	2.08	-	N/A		157	81.1	43	N/A	N/A	-	1547	(2325)	-	5.1	-		5% FGR, Normal O_2
4/4-3	NG	7/18	0.59 (2.0)	0.25	11.7	N/A		162	83.7	302	N/A	N/A	-	1553	(2335)	30.9	5.4	-		5% FGR, Low O_2
4/4-4	NG	7/18	0.59 (2.0)	2.05	11.3	N/A		213	110.0	76	N/A	N/A	-	1547	(2325)	32.1	0	-		Baseline
4/4-5	NG	7/18	0.59 (2.0)	2.02	11.0	N/A		178	92.0	10	N/A	N/A	-	1514	(2265)	29.8	5.1	-		5% FGR, Normal O_2
4/4-6	NG	7/18	0.59 (2.0)	2.00	11.4	N/A		102	52.7	10	N/A	N/A	-	1500	(2240)	29.3	9.9	-		10% FGR, Normal O_2
4/4-7	NG	7/18	0.59 (2.0)	4.15	10.0	N/A		75	38.7	9	N/A	N/A	-	1485	(2213)	25.0	9.3	-		10% FGR, High O_2
4/4-8	NG	7/18	0.59 (2.0)	0.30	11.5	N/A		75	38.7	152	N/A	N/A	-	1571	(2368)	27.3	10.3	-		10% FGR, Low O_2
4/4-9	NG	7/18	0.59 (2.0)	0.20	11.6	N/A		251	129.7	86	N/A	N/A	-	1579	(2382)	31.7	0	-		No FGR, Low O_2
4/4-10	NG	7/19	0.59 (2.0)	2.05	11.8	N/A		52	26.9	33	N/A	N/A	-	1559	(2347)	26.3	14.0	-		15% FGR, Normal O_2
4/4-11	NG	7/19	0.59 (2.0)	2.05	10.6	N/A		280	144.7	10	N/A	N/A	-	1529	(2293)	30.3	0	-		Baseline
4/4-12	NG	7/19	0.59 (2.0)	2.04	10.8	N/A		46	23.8	14	N/A	N/A	-	1485	(2214)	25.6	15.5	-		15% FGR, Normal O_2
4/4-13	NG	7/19	0.59 (2.0)	1.95	9.9	N/A		38	19.6	38	N/A	N/A	-	1510	(2250)	19.4	19.3	-		Maximum FGR, Normal O_2
4/4-14	NG	7/19	0.59 (2.0)	2.10	10.1	N/A		310	160.2	28	N/A	N/A	-	1610	(2439)	25.2	0	-		Baseline
4/4-15	NG	7/19	0.59 (2.0)	4.05	9.5	N/A		239	123.5	21	N/A	N/A	-	1531	(2297)	25.7	0	-		No FGR, High O_2
4/4-16	NG	7/19	0.59 (2.0)	4.05	8.9	N/A		38	19.6	16	N/A	N/A	-	1507	(2253)	14.8	16.6	-		Maximum FGR, High O_2
4/4-17	NG	7/20	0.56 (1.9)	0.40	11.3	N/A		227	117.3	166	N/A	N/A	-	1533	(2300)	32.7	0	-		No FGR, Low O_2
4/4-18	NG	7/20	0.59 (2.0)	0.26	11.4	N/A		68	35.1	239	N/A	N/A	-	1562	(2352)	27.3	10.1	-		10% FGR, Low O_2
4/4-19	NG	7/20	0.59 (2.0)	0.33	11.2	N/A		51	26.3	109	N/A	N/A	-	1569	(2365)	24.4	12.9	-		15% FGR, Low O_2
4/4-20	NG	7/20	0.59 (2.0)	0.21	11.3	N/A		35	18.1	173	N/A	N/A	-	1561	(2351)	22.2	17.1	-		Maximum FGR, Low O_2
4/4-21	NG	7/20	0.59 (2.0)	0.41	11.4	N/A		258	133.3	140	N/A	N/A	-	1623	(2461)	29.5	0	-		No FGR, Low O_2
4/4-22	NG	7/20	0.59 (2.0)	4.14	9.2	N/A		216	111.6	0	N/A	N/A	-	1538	(2309)	24.1	0	-		No FGR, High O_2
4/4-23	NG	7/20	0.59 (2.0)	2.00	10.6	N/A		258	133.3	0	N/A	N/A	-	1539	(2310)	30.0	0	-		Baseline

* dry corrected to 3% O_2

N/A = Not available -(Hot line out of service)

Continued

TABLE C-1. Continued

Test No.	Fuel	Date, 1979	Heat Input Rate MW	(10^6 Btu/h)	O_2 %	CO_2 %	NO_x ppm*	NO_x ng/J	NO ppm*	NO ng/J	CO ppm*	HC ppm*	SO_2 ppm*	SO_3 ppm*	Stack Temp K	(°F)	Furnace Effic. %	FGR %	Water/Steam Injection Rate g/s	(lb/h)	Comments
4/5-1	No.2	7/23	0.55	(1.9)	4.05	12.1	N/A		329	181.9	10	N/A	N/A	-	1530	(2294)	28.8	----	-		Excess O_2 variation at full capacity.
4/5-2	No.2	7/23	0.55	(1.9)	2.05	13.8	N/A		375	207.3	57	N/A	N/A	-	1544	(2320)	34.1	----	-		Baseline
4/5-3	No.2	7/23	0.55	(1.9)	1.30	14.0	N/A		384	212.3	238	N/A	N/A	-	1525	(2285)	35.5	----	-		Excess O_2 variation at full capacity.
4/5-4	No.2	7/23	0.55	(1.9)	2.95	12.9	N/A		364	201.2	10	N/A	N/A	-	1547	(2325)	31.1	----	-		Excess O_2 variation at full capacity.
4/6-1	No.2	7/23	0.28	(1.0)	4.10	12.9	N/A		181	100.1	21	N/A	N/A	-	1426	(2107)	32.1	----	-		Excess O_2 variation at low firing rate.
4/6-2	No.2	7/23	0.33	(1.1)	2.15	12.8	N/A		272	150.4	14	N/A	N/A	-	1494	(2229)	29.3	----	-		2% O_2, low firing rate
4/6-3	No.2	7/23	0.33	(1.1)	0.35	14.8	N/A		205	113.3	227	N/A	N/A	-	1425	(2106)	37.5	----	-		Excess O_2 variation at low firing rate
4/6-4	No.2	7/27	0.30	(1.0)	4.10	12.1	226	124.9	226	124.9	11	0	-	-	1466	(2180)	27.8	----	-		Excess O_2 variation at low firing rate
4/6-5	No.2	7/27	0.30	(1.0)	1.95	13.6	232	128.3	232	128.3	9	0	-	-	1475	(2195)	32.5	----	-		2% O_2, low firing rate
4/6-6	No.2	7/27	0.30	(1.0)	0.30	15.1	191	105.6	191	105.6	43	2	-	-	1491	(2225)	36.0	----	-		Excess O_2 variation at low firing rate
4/7-1	No.2	7/24	0.55	(1.9)	2.00	13.0	N/A		223	123.3	11	N/A	N/A	-	1533	(2300)	32.0	----	0		Baseline
4/7-2	No.2	7/24	0.55	(1.9)	2.05	14.4	N/A		24	13.3	19	N/A	N/A	-	1533	(2300)	33.8	----	5.38	(42.7)	Steam Injection
4/7-3	No.2	7/24	0.55	(1.9)	2.07	14.0	N/A		47	26.0	28	N/A	N/A	-	1514	(2265)	34.1	----	3.78	(30.0)	Steam Injection
4/7-4	No.2	7/24	0.55	(1.9)	2.03	14.0	N/A		78	43.1	28	N/A	N/A	-	1551	(2332)	33.4	----	2.52	(20.0)	Steam Injection
4/7-5	No.2	7/24	0.55	(1.9)	2.10	14.0	N/A		141	77.9	24	N/A	N/A	-	1553	(2335)	33.8	----	1.32	(10.5)	Steam Injection
4/7-6	No.2	7/24	0.55	(1.9)	2.07	13.2	N/A		271	149.8	24	N/A	N/A	-	1559	(2346)	31.7	----	0		Baseline
4/8-1	No.2	7/25	0.52	(1.8)	3.97	12.5	243	134.3	243	134.3	11	22	340	-	1533	(2300)	30.1	0	-		No FGR, High O_2
4/8-2	No.2	7/25	0.55	(1.9)	3.98	13.6	116	64.1	116	64.1	11	20	212	-	1567	(2361)	27.9	9.0	-		10% FGR, High O_2
4/8-3	No.2	7/25	0.55	(1.9)	4.00	13.6	149	82.4	149	82.4	11	19	259	-	1523	(2292)	31.3	5.4	-		5% FGR, High O_2
4/8-4	No.2	7/25	0.55	(1.9)	4.00	12.5	76	42.0	76	42.0	11	25	229	-	1329	(2292)	21.6	15.7	-		15% FGR, High O_2
4/8-5	No.2	7/25	0.55	(1.9)	4.10	11.9	72	39.8	72	39.8	11	22	205	-	1520	(2276)	20.1	15.9	-		Maximum FGR, High O_2
4/8-6	No.2	7/25	0.55	(1.9)	4.00	14.1	233	128.8	233	128.8	11	18	285	-	1615	(2448)	32.4	0	-		No FGR, High O_2
4/8-7	No.2	7/25	0.55	(1.9)	2.10	13.0	219	121.1	219	121.1	10	23	236	-	1545	(2322)	31.5	0	-		Baseline
4/8-8	No.2	7/25	0.55	(1.9)	2.00	13.4	66	36.5	66	36.5	9	7	272	-	1556	(2341)	25.2	18.0	-		Maximum FGR, Normal O_2
4/8-9	No.2	7/26	0.55	(1.9)	2.10	14.8	246	136.0	246	136.0	8	19	235	-	1553	(2335)	36.6	0	-		Baseline
4/8-10	No.2	7/26	0.55	(1.9)	1.95	14.2	57	31.5	57	31.5	9	6	257	-	1535	(2304)	25.3	21.2	-		Maximum FGR, Normal O_2
4/8-11	No.2	7/26	0.55	(1.9)	2.10	14.3	90	49.8	90	49.8	9	12	211	-	1578	(2380)	27.3	14.7	-		15% FGR, Normal O_2
4/8-12	No.2	7/26	0.55	(1.9)	2.10	14.3	124	68.5	124	68.5	9	13	313	-	1547	(2325)	30.7	10.2	-		10% FGR, Normal O_2
4/8-13	No.2	7/26	0.55	(1.9)	1.75	15.0	140	77.4	140	77.4	9	8	235	-	1541	(2315)	35.0	5.3	-		5% FGR, Normal O_2
4/8-14	No.2	7/26	0.55	(1.9)	0.90	15.4	181	100.1	181	100.1	103	14	271	-	1541	(2315)	35.8	6.1	-		5% FGR, Low O_2
4/8-15	No.2	7/26	0.55	(1.9)	0.60	15.2	55	30.4	55	30.4	132	-	258	-	1553	(2336)	27.9	19.8	-		Maximum FGR, Low O_2
4/8-16	No.2	7/26	0.55	(1.9)	0.60	14.9	77	42.6	77	42.6	256	16	319	-	1569	(2365)	28.9	16.8	-		15% FGR, Low O_2
4/8-17	No.2	7/26	0.55	(1.9)	0.65	14.9	109	60.2	109	60.2	345	17	316	-	1543	(2318)	33.1	10.0	-		10% FGR, Low O_2
4/8-18	No.2	7/26	0.55	(1.9)	0.80	14.8	339	187.4	339	187.4	339	16	280	-	1566	(2360)	36.3	0	-		No FGR, Low O_2
4/8-19	No.2	7/27	0.55	(1.9)	0.72	-	359	198.5	359	198.5	169	2	-	-	1522	(2280)	37.8	0	-		No FGR, Low O_2
Except for Test 4/12-1, Flame Temperature Profile Measurements were made during all of the following tests.																					
4/9-1	NG	7/31	0.59	(2.0)	3.90	9.5	126	65.1	126	65.1	3	0	0	-	1557	(2343)	24.6	----	-		Excess O_2 variation at full capacity
4/9-2	NG	7/31	0.59	(2.0)	2.15	10.6	172	88.9	172	88.9	5	5	0	-	1521	(2270)	30.6	----	-		Baseline
4/9-3	NG	7/31	0.59	(2.0)	0.55	11.4	185	95.6	185	95.6	80	4	0	-	1535	(2303)	32.9	----	-		Excess O_2 variation at full capacity
4/10-1	NG	7/31	0.29	(1.0)	4.10	9.9	149	77.0	149	77.0	2	3	0	-	1499	(2239)	25.3	----	-		Excess O_2 variation at half capacity
4/10-2	NG	7/31	0.29	(1.0)	2.00	11.0	180	93.0	180	93.0	2	2	0	-	1535	(2303)	28.0	----	-		2% O_2, half capacity
4/10-3	NG	7/31	0.29	(1.0)	0.40	12.0	179	92.5	179	92.5	131	2	0	-	1530	(2294)	31.3	----	-		Excess O_2 variation at half capacity

* dry corrected to 3% O_2

N/A = Not available - (Hot line out of service)

Continued

TABLE C-1. Continued.

Test No.	Fuel	Date, 1979	Heat Input Rate MW (10^6 Btu/h)	O_2 %*	CO_2 %*	NO_x ppm*	NO_x ng/J	NO ppm*	NO ng/J	CO ppm*	HC ppm*	SO_2 ppm*	SO_3 ppm*	Stack Temp K	Stack Temp (°F)	Furnace Effic. %	FGR %	Water/Steam Injection Rate g/s	Water/Steam Injection Rate (lb/h)	Comments
4/11-1	NG	7/31	0.59 (2.0)	1.97	11.0	180	93.0	180	93.0	5	4	0	-	1511	(2260)	30.4	-	2.52	(20.0)	Water Injection
4/11-2	NG	7/31	0.59 (2.0)	2.00	11.0	116	59.9	116	59.9	5	2	0	-	1505	(2250)	28.4	-	5.04	(40.0)	Water Injection
4/11-3	NG	7/31	0.59 (2.0)	1.90	11.0	221	114.2	221	114.2	5	2	0	-	1489	(2220)	33.4	-	0		Baseline
4/12-1	NG	8/1	0.59 (2.0)	1.90	11.0	N/A		200	103.3	9	N/A	N/A	-	1521	(2278)	31.9	0	-		Baseline
4/12-2	NG	8/1	0.59 (2.0)	2.00	10.6	N/A		52	26.9	4	N/A	N/A	-	1510	(2259)	24.9	12.6	-		15% FGR, Normal O_2
4/13-1	No.2	8/1	0.30 (1.0)	4.10	12.3	N/A		250	138.5	5	N/A	N/A	-	1525	(2286)	26.2	-	-		Excess O_2 Variation at low firing rate
4/13-2	No.2	8/1	0.30 (1.0)	1.97	14.1	N/A		303	167.9	5	N/A	N/A	-	1516	(2270)	32.5	-	-		2% O_2 low firing rate
4/13-3	No.2	8/1	0.30 (1.0)	0.40	15.6	N/A		258	142.9	39	N/A	N/A	-	1531	(2297)	35.9	-	-		Excess O_2 variation at low firing rate
4/14-1	No.2	8/1	0.55 (1.9)	4.00	12.0	N/A		307	170.1	5	N/A	N/A	-	1518	(2272)	28.9	-	-		Excess O_2 variation at full capacity
4/14-2	No.2	8/1	0.55 (1.9)	2.00	13.2	N/A		374	207.2	38	N/A	N/A	-	1526	(2288)	32.9	-	-		Baseline
4/14-3	No.2	8/1	0.55 (1.9)	1.15	13.6	N/A		354	196.1	362	N/A	N/A	-	1513	(2263)	34.8	-	-		Excess O_2 variation at full capacity
4/15-1	No.2	8/2	0.55 (1.9)	1.90	13.6	N/A		262	145.2	38	N/A	N/A	-	1556	(2342)	33.1	-	-		Baseline
4/15-2	No.2	8/2	0.55 (1.9)	2.05	13.7	N/A		52	28.8	95	N/A	N/A	-	1525	(2285)	32.3	-	5.04	(40.0)	Steam Injection
4/16-1	No.2	8/2	0.55 (1.9)	2.00	14.0	N/A		248	137.4	14	N/A	N/A	-	1533	(2300)	35.1	0	-		Baseline
4/16-2	No.2	8/2	0.55 (1.9)	2.00	14.0	N/A		95	52.6	9	N/A	351	0	1515	(2268)	29.8	12.9	-		15% FGR, Normal O_2, Goksoyr-Ross (SO_x) Test

* dry corrected to 3% O_2

N/A = Not available - (Hot line out of service)

APPENDIX D

CALCULATION OF INCREMENTAL FUEL REQUIREMENTS OF COMBUSTION MODIFICATIONS TO A STEEL FURNACE

The calculation of the incremental heat requirement of steam or water injection or flue gas recirculation when applied to a steel furnace necessitates the assumption that there is no effect of these modifications on furnace thermal efficiency other than the additional thermal losses caused by having to heat the injected materials to combustion temperatures. Thus, the effects of the combustion modifications on convective or radiative heat transfer rates, which also affect furnace efficiency, are not considered in this report. It is also assumed that the furnace is 100% efficient in transferring heat to the H_2O or recirculated flue gas. Thus, the incremental fuel requirements determined in this section would be multiplied by $1/\eta_{th}$ to obtain the values for a furnace of thermal efficiency η_{th}.

In an actual application, the convective heat transfer rates from the combustion gases to the steel itself will probably increase because of the higher mass flow of gases through the furnace brought about by the injection of additional material. This may partially offset the efficiency degradation associated with the added thermal load of the injected material.

In addition, the radiative heat transfer rate may also be increased by flue gas recirculation or by steam or water injection. The increase in the partial pressure of CO_2 and H_2O resulting from the injection of these materials would tend to increase the emissivity of the combustion gases and, therefore, the radiative heat transfer rate to the steel.

The effects of altered convection and radiative heat transfer need to be studied further in order to develop more meaningful efficiency assessments of the combustion modifications discussed in this section.

The incremental heat requirements for steel furnace combustion modifications are calculated in the order of increasing complexity, beginning with steam injection, followed by water injection and, finally, flue gas recirculation. The percent increase in heat load is equal to the percent increase in fuel required.

The incremental heat requirement per burner of steam injection at 5.0 g/s (40 lb/hr) injected steam flow rate is defined as follows:

Δh_{STM} = heat required to take steam from the injection conditions to the furnace bulk gas temperature, T_F

$= \dot{m}_{STM} (h_F - h_{IN})$

For $P_{IN} = 1$ atm, T_{IN}=273K, P_F=1 atm, and T_F=1755K (typical measured operating temperature)

h_F = 3384 kJ/kg (1,455 Btu/lb) and

h_{IN} = 419 kJ/kg (180 Btu/lb)

Thus,

Δh_{STM} = 0.015 MW (51,000 Btu/hr)

= 2.56% of experimental burner capacity of 0.586 MW (2.0x10^6 Btu/hr)

The incremental heat requirement per burner for 5.0 g/s (40 lb/hr) injected water flow rate is determined below. This requirement includes the heat necessary to raise the water temperature to the boiling point, complete the phase change to steam, and heat the steam to the furnace bulk gas temperature.

$$\Delta h_{WATER} = \Delta h_{STM} + \dot{m}_{H_2O} \left[\Delta h_{fg} + Cp_{H_2O(\ell)} (T_{B.P.} - T_{IN})\right]$$

Where

Δh_{fg} = heat of vaporization of water at p = 1 atm,

T = 373K (212°F) = 2256 kJ/kg (970 Btu/lb)

$Cp_{H_2O(\ell)}$ = specific heat of water

$T_{B.P.}$ = 373K (212°F) = boiling point of water at p=1 atm

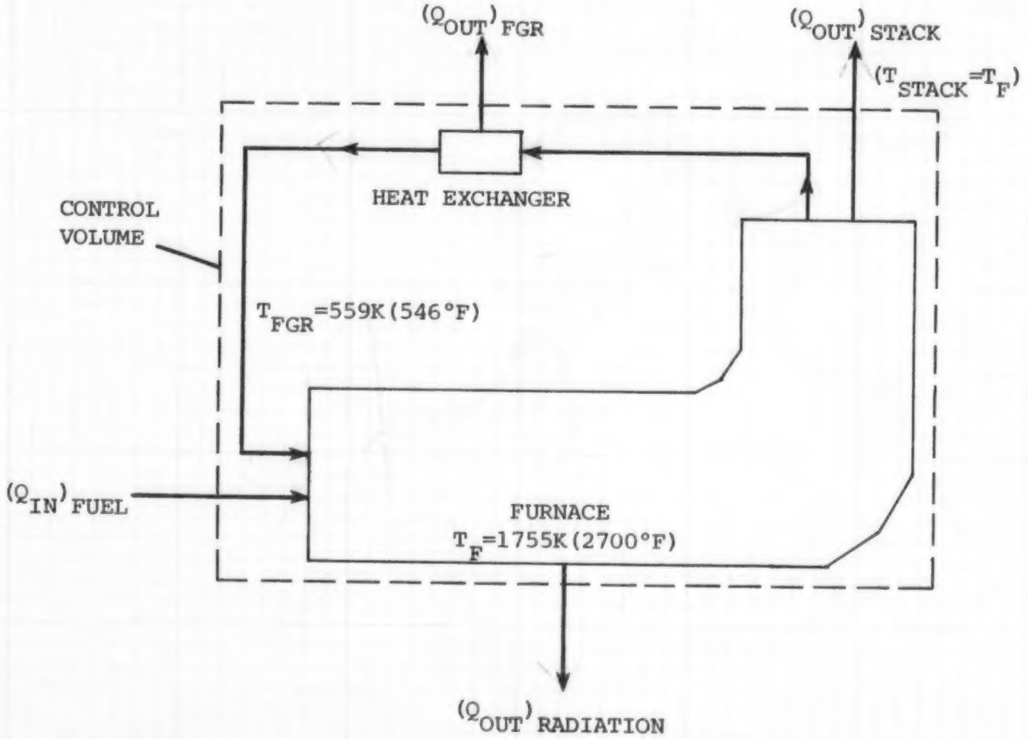
T_{IN} = injected water temperature

For T_{IN} = 294K (70°F),

$$\Delta h_{WATER} = 0.028 \text{ MW } (95{,}480 \text{ Btu/hr})$$

$$= 4.75\% \text{ of experimental burner capacity}$$

The heat losses associated with flue gas recirculation in a steel furnace arise from the cooling of the flue gas temperature to the reinjection temperature. In the experimental arrangement most of this cooling occurred in an air-gas heat exchanger, and no heat was recovered, i.e., all of the heat was lost to the ambient air. It is emphasized here that in a practical application of flue gas recirculation much of this heat could be retained within the furnace proper by combustion air preheat or some other means of waste heat recovery. The following diagram illustrates the calculation of furnace efficiency for the steel furnace.



$(Q_{OUT})_{FGR}$
$(Q_{OUT})_{STACK}$
$(T_{STACK}=T_F)$
HEAT EXCHANGER
CONTROL VOLUME
T_{FGR}=559K(546°F)
$(Q_{IN})_{FUEL}$
FURNACE
T_F=1755K(2700°F)
$(Q_{OUT})_{RADIATION}$

One observes from this drawing the increased heat loss from the steel furnace with FGR as compared to a furnace without FGR. In the calculations which follow we assume that there are no factors influencing the furnace efficiency other than this heat loss. This assumption may not be strictly valid, however, for two reasons:

1. The convective heat transfer coefficient of the combustion gases in the furnace should increase with the increased mass flow through the furnace due to FGR, thereby increasing the convective heat transfer to the steel.
2. The recirculation of flue gases containing large amounts of the radiative species CO_2 and H_2O may increase the emissivity of the combustion gases within the furnace, thus increasing radiative heat transfer rates to the steel. (This is also especially true for the case of H_2O injection where the volume fraction of H_2O in the combustion gases is significantly increased.)

The incremental heat (fuel) requirement for 20 percent FGR is determined below:

$$\Delta h_{FGR} = \dot{m}_{FGR}(Cp)_{FGR}(T_F - T_{FGR})$$

where $(Cp)_{FGR}$ = specific heat of the flue gas

T_{FGR} = flue gas temperature at point of injection into the furnace

$\dot{m}_{FGR}$ = recirculated flue gas mass flow rate

For Test #4/4-13,

T_F = 1755K (2700°F), T_{FGR} = 559K(546°F),

$(C_p)_{FGR}$=1.09 kJ/Kg-K (0.26 Btu/lbm-°R),

and $\dot{m}_{FGR}$=0.051 kg/s (400.8 lbm/hr)

and so

Δh_{FGR} = 0.066 MW (224,464 Btu/hr)

= 11.2% of burner heat input capacity.

Thus, with no waste heat recovery, and neglecting the effects of the combustion modifications on convective and radiative heat transfer, the additional fuel requirements are summarized in Table D-2.

TABLE D-1. INCREMENTAL FUEL REQUIREMENTS OF COMBUSTION MODIFICATIONS TO A STEEL FURNACE

Modification	Percent Increase in Fuel Consumption
Steam Injection	2.56
Water Injection	4.75
Flue Gas Recirculation (w/o Waste Heat Recov.)	11.2